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BEFORE
THE TENNESSEE REGULATORY AUTHORITY

PETITION OF KINGSPORT POWER COMPANY D/B/A AEP APPALACHIAN POWER FOR A GENERAL RATE CASE	)	Docket No. 16-00001

DIRECT TESTIMONY
of
WILLIAM H. NOVAK

ON BEHALF OF
THE CONSUMER PROTECTION AND ADVOCATE DIVISION
OF THE
TENNESSEE ATTORNEY GENERAL'S OFFICE

June 24, 2016

IN THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE:	)	
	)	
PETITION OF KINGSPORT POWER COMPANY d/b/a AEP APPALACHIAN POWER GENERAL RATE CASE AND MOTION FOR PROTECTIVE ORDER	))))	**DOCKET NO. 16-00001**
	)	

AFFIDAVIT

I, William H. Novak, CPA, on behalf of the Consumer Advocate Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Division.

WILLIAM H. NOVAK

EMILY KNIGHT
STATE OF TENNESSEE NOTARY PUBLIC
DAVIDSON COUNTY
My Commission Expires MAY 6, 2019

Sworn to and subscribed before me
this 23rd day of June, 2016.

NOTARY PUBLIC

My commission expires: May 6, 2019

TABLE OF CONTENTS

ATTACHMENTS

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION FOR THE RECORD.

A1. My name is William H. Novak. My business address is 19 Morning Arbor Place, The Woodlands, TX, 77381. I am the President of WHN Consulting, a utility consulting and expert witness services company.[1]

Q2. PLEASE PROVIDE A SUMMARY OF YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. A detailed description of my educational and professional background is provided in Attachment WHN-1 to my testimony. Briefly, I have both a Bachelor's degree in Business Administration with a major in Accounting, and a Master's degree in Business Administration from Middle Tennessee State University. I am a Certified Management Accountant, and am also licensed to practice as a Certified Public Accountant.

My work experience has centered on regulated utilities for over 30 years. Before establishing WHN Consulting, I was Chief of the Energy & Water Division of the Tennessee Regulatory Authority where I had either presented testimony or advised the Authority on a host of regulatory issues for over 19 years. In addition, I was previously the Director of Rates & Regulatory Analysis for two years with Atlanta Gas Light Company, a natural gas distribution utility with operations in Georgia and Tennessee. I also served for two years as the Vice President of Regulatory Compliance for Sequent Energy Management, a natural

[1] State of Tennessee, Registered Accounting Firm ID 3682.

gas trading and optimization entity in Texas, where I was responsible for ensuring the firm's compliance with state and federal regulatory requirements.

In 2004, I established WHN Consulting as a utility consulting and expert witness services company. Since 2004 WHN Consulting has provided testimony or consulting services to state public utility commissions and state consumer advocates in at least ten state jurisdictions as shown in Attachment WHN-1.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A3. I am testifying on behalf of the Consumer Protection & Advocate Division ("CPAD" or "the Consumer Advocate") of the Tennessee Attorney General's Office.

Q4. HAVE YOU PRESENTED TESTIMONY IN ANY PREVIOUS RATE CASES CONCERNING KINGSPORT POWER COMPANY?

A4. Yes. I've presented testimony in TRA Dockets U-86-7472, 89-02126, 90-05735 and 92-04425 concerning rate cases involving Kingsport Power Company ("KPC" or "the Company") as well as dockets for other generic tariff and rulemaking matters. In addition, I previously advised the TRA on issues in other KPC dockets in cases where I did not present testimony.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A5. My testimony will support and address the CPAD's positions and concerns with respect to the Company's Petition. Specifically, I will address the following:

i. CPAD's proposed attrition period revenue calculations;

ii. CPAD's proposed attrition period rate base calculations;

iii. CPAD's proposed attrition period pension and other post-employment expense calculations;

iv. CPAD's proposal on various policy issues; and

v. CPAD's proposed rate design.

In addition to my own testimony, Mr. Ralph Smith will testify to the CPAD's calculation of operating expenses and taxes other than income taxes. Also, Dr. Chris Klein will testify to the CPAD's proposed cost of capital. As the manager of the team conducting the investigation of this rate case on behalf of the CPAD, I am also responsible for the theory of all adjustments made in arriving at our estimate of the Company's rate of return under present rates.

Q6. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARATION OF YOUR TESTIMONY?

A6. I have reviewed the Company's Rate Case Application filed on January 4, 2016, along with the testimony and exhibits presented with its filing. In addition, I have reviewed the Company's workpapers supporting its attrition period revenues and rate base. I have also reviewed the Company's responses to the relevant data requests submitted by the TRA as well as the Company's responses to CPAD's own discovery requests (and documents filed in connection with those requests and responses) in these same areas.

Q7. MR. NOVAK, BEFORE WE BEGIN WITH YOUR ANALYSES OF THE COMPANY'S RATE CASE, DO YOU HAVE ANY COMMENTS ON HOW THE COMPANY'S FILING WAS PREPARED AND PRESENTED TO THE TRA?

A7. Yes. The Company's rate case filing as well as its responses to the Minimum Filing Requirement Guidelines[2] were presented to the TRA without a clear audit trail as to how its individual schedules were calculated. Specifically, there are no workpaper numbers, footnotes or source documentation included in the Company's filing demonstrating how their case was put together. In addition, many times the calculations in the Company's spreadsheets contained "hard-coded" numbers that I was unable to link to the source data. As a result, the CPAD was forced to issue an unprecedented number of data requests[3] in this docket, often without ever getting to the source of the Company's calculations.

Q8. DID THIS LACK OF A CLEAR AUDIT TRAIL CAUSE ISSUES FOR YOUR ANALYSIS OF THE COMPANY'S CASE?

A8. Yes. Since there was no clear audit trail in the Company's case, I was unable to use the Company's filing for any type of guidance to my own calculations. This is unfortunate, because the Company's witnesses obviously have more first-hand

[2] The Company consistently refers to the TRA's Minimum Filing Requirement Guidelines as TRA Staff Informal Data Request #1.
[3] 309 total requests with subparts.

experience with KPC's utility operations. However, the Company has been unable to clearly demonstrate this knowledge in a rate case.

To avoid unsubstantiated filings like this in the future, I would recommend that the TRA consider formal rulemaking on rate case minimum filing requirements for all utilities. Such a rulemaking docket would clearly lay out the expectations that are expected when rate cases are filed.

Q9. MR. NOVAK, PLEASE SUMMARIZE YOUR SIGNIFICANT FINDINGS AND MAJOR RECOMMENDATIONS IN THIS CASE.

A9. My most significant findings and recommendations are as follows:

- I recommend that the test period and attrition period of December 31, 2014 and December 31, 2016 proposed by the Company be discarded. Instead, I recommend that the TRA adopt a test period for the 12 months ended December 31, 2015 and an attrition period for the 12 months ending December 31, 2017.
- I recommend that the Street Lighting rate base and income be included in the revenue deficiency calculation and rates be set by the TRA for these customers.
- I recommend that the TRA adopt a revenue deficiency of $6,951,869 as appropriate for the Company to earn a 5.75% return on rate base as recommended by Dr. Klein.
- I recommend that the TRA recover this revenue deficiency from all customer classes based on the current margin provided by each customer class.
- I recommend that the TRA exclude all fuel and power costs from the base tariff rate and that a mechanism like that used for gas company audits be used by the Company to recover those costs, and further that those costs be separately stated as a line item on each customer's bill.
- I recommend that the TRA discontinue the Company's Tennessee Inspection Fee Rider.

Q10. WHAT TEST PERIOD AND ATTRITION PERIOD HAS THE CPAD ADOPTED FOR THIS CASE?

A10. The Company has proposed the twelve months ended December 31, 2014 as its test period with attrition adjustments through the twelve months ending December 31, 2016. These proposed periods are a holdover from the Company's 2015 filing that was later withdrawn. However, at this point in time, these proposed periods appear to be somewhat stale. As a result, I am recommending that the TRA adopt the twelve months ended December 31, 2015, as the appropriate test period since this reflects the most recent fiscal year close for the Company. I also recommend that the TRA adopt the twelve months ending December 31, 2017 as the appropriate attrition year since this will be the first year that any new rates granted by the TRA will be in effect.

Q11. HAVE YOU CAUSED TO BE FILED A MULTI-PAGE EXHIBIT IN THIS CASE CONSISTING OF 12 SCHEDULES?

A11. Yes. As shown on CPAD Exhibit, Schedule 1, our proposed revenue deficiency calculation required to produce the 5.75% overall return recommended by Dr. Klein results in a revenue increase of approximately $6.95 million. The Company has requested an increase in rates of 19.27% on existing gross margin (revenues less purchased power cost) while I am recommending an increase of only 11.06% on existing gross margin.

[Testimony continues on next page]

I. ATTRITION PERIOD RATE BASE

Q12. MR. NOVAK, PLEASE SUMMARIZE YOUR CALCULATION OF ATTRITION PERIOD RATE BASE.

A12. The development of my proposed Rate Base is shown on CPAD Exhibit, Schedules 2 and 3. As shown on CPAD Exhibit, Schedule 2, I began with the test period balance for each of the components of Rate Base at December 31, 2015, from the Company's books and records. I then made adjustments to allocate transmission plant from Rate Base. I also made various adjustments for known and reasonably anticipated events, producing an attrition year rate base of $74,678,058 as shown on CPAD Exhibit, Schedule 2. In my opinion, this Rate Base represents the net investment upon which the Company should be allowed the opportunity to earn a fair rate of return.

Q13. DID THE COMPANY MAKE ADJUSTMENTS SIMILAR TO YOURS IN THEIR FORECAST OF RATE BASE?

A13. Not entirely. As shown on CPAD Exhibit, Schedule 3, the Company reduced their Rate Base calculation by $4,198,106 for the investment associated with providing Street Lighting Service.[4] I do not consider Street Lighting to be an unregulated service and have therefore included its related investment within the CPAD's Rate Base forecast.

[4] The Company offers no support in its filings as to its rationale for apparently treating Street Lighting Service as an unregulated service.

Q14. MR. NOVAK, PLEASE EXPLAIN THE COMPONENTS THAT MAKE UP YOUR TEST PERIOD AND ATTRITION PERIOD RATE BASE CALCULATIONS AS SHOWN ON CPAD EXHIBIT, SCHEDULE 2.

A14. **<u>Line 1, Utility Plant in Service $161,469,371.</u>** Utility Plant in Service is the largest component of rate base and represents the average amount of utility assets for the attrition year upon which the Company should be allowed the opportunity to earn a return. To compute attrition year Utility Plant in Service, I began with the test period balance for total utility plant of $176,806,762[5] and then reduced this figure by the amount of transmission plant associated with the PJM allocation, leaving only the test period distribution plant of $145,482,565. Next, I increased the test period distribution plant by the Company's budgeted 2016 and 2017 monthly capital expenditures for distribution plant through the mid-point of the attrition period.[6] As shown in Table 1 below, the Company's monthly distribution plant capital budget for 2016 and 2017 of $990,445 and $1,089,882 closely approximates its most recent historical monthly capital expenditures. I therefore adopted the Company's proposed monthly capital budget into my forecast of Plant in Service.

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[5] CPAD Rate Base Workpaper RB-10-1-1.00.

[6] The Company originally forecasted $5,837,116 ($486,426 monthly) as its 2016 distribution plant capital addition budget as shown on Page 8 of the Direct Testimony of Company witness Philip Wright. This forecast was later increased to $11,885,336 ($990,445 monthly) in response to CPAD Data Request 2-49. See Company supplemental response to CPAD Data Request 2-49 for Company's explanation for this increase.

Table 1 – Historical & Budget Monthly Distribution Capital Expenditures[7]	
Historical/Forecast Period	**Amount**
2009 – 2015 (7 Year Average)	$661,230
2010 – 2015 (6 Year Average)	699,536
2011 – 2015 (5 Year Average)	751,832
2012 – 2015 (4 Year Average)	809,986
2013 – 2015 (3 Year Average)	902,023
2014 – 2015 (2 Year Average)	866,200
2015 – 2015 (1 Year Average)	1,142,261
Company 2016 Budget Forecast	990,445
Company 2017 Budget Forecast	1,089,882

I then reduced the test period distribution plant by the 4-year average of the Company's monthly historical distribution retirements through the mid-point of the attrition period. As shown in Table 2 below, the 4-year average of the Company's monthly distribution retirements of $135,435 closely approximates their most recent historical monthly retirements.

Table 2 – Historical Monthly Distribution Retirements[8]	
Historical Period	**Amount**
2009 – 2015 (7 Year Average)	$124,635
2010 – 2015 (6 Year Average)	120,543
2011 – 2015 (5 Year Average)	126,386
2012 – 2015 (4 Year Average)	135,435
2013 – 2015 (3 Year Average)	139,795
2014 – 2015 (2 Year Average)	133,606
2015 – 2015 (1 Year Average)	160,583

By taking the adjustments described above for plant additions and retirements, I was able to calculate my forecast for attrition period Plant in Service of $161,469,371.

[7] CPAD Rate Base Workpaper RB-10-5-1.00.
[8] CPAD Rate Base Workpaper RB-10-4-1.00.

Q15 PLEASE CONTINUE WITH YOUR EXPLANATION OF THE REMAINING COMPONENTS OF THE RATE BASE CALCULATION.

A15. **Line 2, Property Held for Future Use $0.** This item represents currently unused plant that the Company expects to eventually devote to providing utility service. The specific plant in question has a historical cost of $34,829 and has been on the Company's books for at least seven years. The TRA has traditionally allowed Property Held for Future Use to be included in Rate Base when it is expected to be converted to utility plant within a *reasonable* amount of time. In this particular case, it appears that the Company has no immediate plans for converting this plant into anything that would be considered used and useful in providing utility service. I have therefore removed its cost from Rate Base. Further, I would recommend that the TRA order the Company to reclassify this item as unregulated utility property until such time that it can be converted to utility plant.

Line 3, Construction Work in Progress $3,392,856. This item represents plant currently under construction that will soon become used and useful in providing utility service to the Company's customers. To project Construction Work in Progress, I used a seven-year historical average of the annual balances in this account.[9]

Line 4, Materials & Supplies $231,854. This item represents the carrying value of miscellaneous materials and represents an investment on which the Company should be allowed to earn a reasonable return. To project Materials & Supplies, I used a seven-year historical average of the annual balances in this account.[10]

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[9] CPAD Rate Base Workpaper RB-12-1-1.00.
[10] CPAD Rate Base Workpaper RB-13-1-1.00.

Line 5, Prepayments $1,900,772. This item represents a variety of costs that the Company has paid in advance for taxes, insurance, employee benefits and other items. Because these costs are paid in advance of when they are actually required, they represent a capitalized investment on which the Company should be allowed to earn a reasonable return. As these Prepayments are used, their cost is amortized to operating expense. To project Prepayments, I used a three-year historical average of the annual balances in this account since it was most representative of the current cost.[11]

Line 7, Accumulated Depreciation $60,051,552. This item represents the amount of depreciation which has accrued over the life of the various capital assets included within Utility Plant in Service as described above. In this case, the Company has proposed new depreciation rates that annually increase the depreciation expense on distribution plant by $259,618.[12] According to the Company, these new depreciation rates "…are necessary because of changes in average service lives and net salvage estimates."[13] As a result, I have reflected the Company's proposed depreciation rates within my calculation of depreciation expense.[14] These depreciation rates also produced $6,260,675 in depreciation expense that is reflected on the Income Statement in the CPAD Exhibit. All other differences between the Company and my attrition year Accumulated Depreciation primarily relate to the different projections of Utility Plant in Service as described above.

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[11] CPAD Rate Base Workpaper RB-14-1-1.00.
[12] CPAD Rate Base Workpaper RB-20-2-1.00.
[13] Direct testimony of Company witness Jason Cash, Page 5.
[14] CPAD Rate Base Workpaper RB-20-1-1.00.

__**Line 8, Accumulated Deferred Income Taxes ("ADIT") $25,140,046.**__ This item represents the net amount of income tax that the Company has deferred payment on primarily due to the use of accelerated depreciation methods to compute tax depreciation expense. Since these tax payments have already been paid by customers through rates, their deferral represents a reduction to rate base. To compute ADIT, I calculated a linear regression of historical distribution ADIT against historical distribution Plant in Service. I then applied the results of this regression (with a 94% correlation) to the attrition period distribution Plant in Service described earlier.[15]

__**Line 9, Accumulated Deferred Investment Tax Credit ("ADITC") $0.**__ This item represents the unamortized ADITC generated on property additions placed in service prior to 1971. This tax credit has since been repealed, and as a result, there have been no additions. Because of specific rulings, ADITC generated prior to 1971 for KPC is properly used to reduce Rate Base. As mentioned earlier, the CPAD has proposed to change the attrition period in this case to 2017 since this is closer to the first year that any new rates granted by the TRA will be in effect. Because of this change, ADITC will be fully amortized before the start of the attrition year and should therefore be reflected at a zero ($0) amount in Rate Base.[16]

__**Line 10, Customer Advances $546,604.**__ This item represents non-investor supplied funds from customers for extending utility service that the Company has

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[15] CPAD Rate Base Workpaper RB-21-1-1.00.
[16] CPAD Rate Base Workpaper RB-22-1-1.00.

used to finance a portion of its utility investment and should therefore be included as a deduction in computing Rate Base. To project Customer Advances, I used a two-year historical average of the annual balances in this account since it was most representative of the current cost.[17]

Line 11, Customer Deposits $5,265,608. This item represents amounts advanced by customers to the Company for the privilege of obtaining utility service. These deposits therefore represent a source of non-investor supplied funds which the Company has available to finance a portion of its utility investment and should therefore be included as a deduction in computing Rate Base. To compute Customer Deposits, I calculated a linear regression of historical Customer Deposits against historical distribution Plant in Service. I then applied the results of this regression (with an 89% correlation) to attrition period distribution Plant in Service described earlier.[18]

Line 14, Accrued Interest on Customer Deposits $1,312,985. This item represents the interest accrued on Customer Deposits and owed to the customer when the deposit is refunded. Since this accumulated interest is owed to the customer, it represents a source of non-investor supplied funds which the Company has available to finance a portion of its utility investment and should therefore be included as a deduction in computing Rate Base. To compute Accrued Interest on Customer Deposits, I calculated a linear regression of historical Accrued Interest on Customer Deposits against historical Customer

[17] CPAD Rate Base Workpaper RB-23-1-1.00.
[18] CPAD Rate Base Workpaper RB-24-1-1.00.

Deposits. I then applied the results of this regression (with a 95% correlation) to attrition period Customer Deposits described earlier.[19]

After considering all of the above components, I computed Rate Base as shown on CAPD Exhibit, Schedules 2 and 3 to be $74,678,058.

[Testimony continues on next page]

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[19] CPAD Rate Base Workpaper RB-25-1-1.00.

II. ATTRITION PERIOD REVENUES & PURCHASED POWER EXPENSE

Q16. MR. NOVAK, PLEASE DESCRIBE THE MAJOR AREAS OF DIFFERENCE BETWEEN THE COMPANY'S AND CPAD'S CALCULATIONS OF ATTRITION PERIOD BILLING DETERMINANTS.

A16. The primary differences are different forecasts for normal weather, annualized customer usage and customer growth. As shown in detail on Attachment WHN-2, Schedule 1 and summarized below in Table 3, the CPAD first began with the Company's test period billing determinants for 2015 of 2,097,680,953 KWH, 566,421 bills and 2,294,784 billing demand units. We then adjusted for normal weather, annualized customer usage and annualized customer growth to arrive at attrition billing determinants of 2,097,854,927 KWH, 567,597 bills and 2,303,977 billing demand units.

Table 3 – Summary of CPAD Attrition Period Billing Determinants				
	Test Period	**Weather Adjustment**	**Customer Growth**	**Attrition Period**
Bills	566,421	0	1,176	567,597
Billing Demand	2,294,784	0	9,193	2,303,977
KWH	2,097,680,953	-2,347,559	2,521,533	2,097,854,927

I have also included a detailed comparison with the Company's attrition period billing determinants on Attachment WHN-2, Schedule 2. This comparison is summarized below on Table 4.

Table 4 – Comparison of Company and CAPD Attrition Period Billing Determinants			
	Company	**CAPD**	**Difference**
Bills	567,139	567,597	-458
Billing Demand	2,188,056	2,303,977	-115,921
KWH	2,062,657,243	2,097,854,927	-35,197,684

Q17. HAS THE TRA EVER ADOPTED A WEATHER NORMALIZATION ADJUSTMENT FOR KINGSPORT POWER?

A17. No. To my knowledge, the Company has never proposed a weather normalization adjustment in a rate case prior to this docket. In this case, the Company has proposed to adjust its test period usage for the weather impacts to its Residential, Small General Service, Medium General Service-Secondary, Industrial Power Service-Primary, Electric Heating General Service, Church Service and Public School Service customers.

Q18. DO YOU AGREE WITH THE COMPANY'S WEATHER NORMALIZATION CALCULATIONS?

A18. No. The Company has used a methodology for weather normalization that does not provide a correlation factor (r^2) to explain how much of the deviation in customer usage is explained by weather changes.[20] My own analysis revealed that there was significant correlation between weather and customer usage only in the Company's Residential, Small General Service and Electric Heating General Service tariffs. As a result, these were the only tariffs where I adjusted the test period usage for normal weather. I have included a copy of my weather normalization adjustment calculations for the test period on Attachment WHN-3.

Q19. HOW HAVE YOU ADJUSTED THE ATTRITION PERIOD BILLING DETERMINANTS FOR EXISTING CUSTOMER USAGE?

[20] See Company response to CPAD Data Request 2-43 (Supplemental).

A19. I adjusted industrial customer usage by individually analyzing the sales volumes of the Company's 25 largest customers. These 25 customers represented over 84% of the Company's test period volumes to the large commercial and industrial class.[21]

Q20. HOW WERE SALES VOLUMES FOR ADDED CUSTOMERS COMPUTED?

A20. A historical average of added customers was first calculated. These forecasted customer additions were then multiplied by an average usage volume per customer giving additional attrition period sales volumes.

Q21. HOW WERE THE ATTRITION PERIOD BILLING DETERMINANTS TRANSLATED INTO REVENUES?

A21. The attrition period billing determinants as shown on Attachment WHN-2 were multiplied by the existing base tariff rates[22] along with the 2015 average fuel rider and the current purchased power adjustment rider for each tariff. We also made adjustments to take into account the current TRA Inspection Fee Rider and the prompt payment discount. This gives total attrition period electric service revenues of $152,766,835 as shown on Attachment WHN-4 and summarized below in Table 5.

[21] CPAD Revenue Workpaper R-91.00.
[22] The Company's current base tariff rates also include a provision for fuel cost of 15.8563 mills per KWH, adjusted for losses.

Table 5 – Comparison of Company and CPAD Attrition Period Revenues under Current Rates			
	Company	**CPAD**	**Difference**
Residential Service	$59,442,780	$57,600,039	$1,842,741
Small General Service	2,365,884	2,385,293	-19,409
Medium General Service	10,504,269	11,040,457	-536,188
Large General Service	19,657,936	19,663,638	-5,702
Industrial Power Service	57,804,203	54,288,484	3,515,719
Church Service	952,823	947,307	5,516
Public School Service	2,267,020	2,121,121	145,899
Electric Heating General Service	2,443,736	2,472,814	-29,078
Outdoor Lighting Service	722,983	738,080	-15,097
Street Lighting Service	1,448,049	1,509,602	-61,553
Total Electric Service Revenue	**$157,609,683**	**$152,766,835**	**$4,842,848**

Q22. HOW DID YOU COMPUTE OTHER REVENUES?

A22. Other Revenues primarily consist of forfeited discounts, reconnection charges, miscellaneous service charges and rental income from utility property. To compute Other Revenues, I analyzed the test period amounts and adjusted for growth where appropriate. This produced $1,495,494 in Other Revenues as shown on Attachment WHN-4.

Q23. HOW WAS PURCHASED POWER EXPENSE COMPUTED?

A23. I began with the test period purchased power expense on the Company's books for 2015. I then made adjustments for changes to the attrition period throughput described above and annualized the cost at the current fuel and non-fuel purchased power rates. This produced $134,569,031 in attrition period purchased power expense as shown on Attachment WHN-4.

[Testimony continues on next page]

III. ATTRITION PERIOD PENSION & OTHER POST-EMPLOYMENT BENEFITS

Q24. MR. NOVAK, PLEASE SUMMARIZE YOUR CALCULATION OF PENSION AND OTHER POST-EMPLOYMENT BENEFITS.

A24. The TRA has a long-established policy of only allowing rate recovery of the minimum required contribution for pension and other post-employee benefits ("OPEB") expenses.[23] For 2013, 2014 and 2015, the Company made no contribution to its pension and OPEB plans. Therefore, I included zero ($0) as the appropriate attrition period expense for pension and OPEB expense.[24] These calculations are included in the schedules discussed by Mr. Ralph Smith in his testimony regarding operation and maintenance expenses.

Q25. DID THE COMPANY RECORD ZERO ($0) IN PENSION AND OPEB EXPENSE ON THEIR BOOKS FOR 2013, 2014 AND 2015?

A25. No. KPC records the accrued calculation of its pension and OPEB expense that is provided by its actuary in accordance with specific Financial Accounting Standards Board ("FASB") requirements.[25]

Q26. IS THE TRA REQUIRED TO FOLLOW THIS SPECIFIC ACCOUNTING METHODOLOGY FOR RATE SETTING PURPOSES?

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[23] See specifically TRA Docket 92-14631, Investigation of Proper Regulatory Treatment of Other Post-Employment Benefits for Utilities Regulated by the Tennessee Public Service Commission. This current rate case represents the first time that the results of this docket have been applied to Kingsport Power Company.

[24] CPAD Rate Base Workpaper RB-40-1-1.00.

[25] Specifically, FASB Accounting Standards Codification Topics 715, 960, and 965 as shown in the Company's response to the TRA's Minimum Filing Requirement #43 as well as the Company's response to CPAD Data Request #1-78.

A26. No. Public Utility Commissions generally have broad latitude in setting the accounting methodology for public utilities under their jurisdiction. Financial Accounting Standard #71 ("FAS 71") recognizes that regulatory bodies may in fact set rates using a methodology that departs from other accounting pronouncements. Specifically, FAS 71 reads in part as follows:

> *"This Statement may require that a cost be accounted for in a different manner from that required by another authoritative pronouncement. In that case, this Statement is to be followed because it reflects the economic effects of the rate-making process—effects not considered in other authoritative pronouncements".*[26]

Therefore, the choice of which accounting methodology to adopt for setting rates is completely within the TRA's prerogative.

Q27. WHY SHOULD THE TRA ADOPT THE COMPANY'S MINIMUM REQUIRED CONTRIBUTION FOR RATE SETTING PURPOSES?

A27. Beyond confirming the rate setting policy on pension and OPEB expenses that the TRA has applied consistently to other utilities, there are several reasons that this policy should be extended to KPC.

First, adopting the minimum required contribution most closely matches today's cost with today's customer. The minimum required contribution is also generally

[26] Financial Accounting Standards Board, Statement of Financial Accounting Standards No. 71 – Accounting for the Effects of Certain Types of Regulation, December 1982.

not subject to the same changes in assumptions for market conditions as the actuary's recommended contribution.[27] Finally, the minimum required contribution is typically a more stable and consistent amount and therefore more appropriate for setting rates for the near-term future. I therefore recommend that the TRA adopt the Company's current funding requirement of zero ($0) as the appropriate level of pension and OPEB expense for the attrition year.

[Testimony continues on next page]

[27] These assumptions include discount rates, inflation rates for health care services, the level and type of health care benefits offed to future employees, employment levels, employee turnover and retirement rates, disability rates, eligibility dates, the mix by age and sex of employees, and the expected return earned on plan assets.

IV. RATE DESIGN

Q28. MR. NOVAK, PLEASE SUMMARIZE THE RATE DESIGN PROPOSALS MADE BY THE COMPANY TO RECOVER ITS REVENUE DEFICIENCY.

A28. The Company has proposed using a Class Cost of Service Study to set rates for each of its tariffs. In addition, the Company has proposed a Rate Realignment Rider to further adjust rates between tariffs after the conclusion of this rate case. The Company has also made other proposed policy changes that could have an impact on rates which I discuss later in my testimony.

Q29. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF THE ALLOCATION PROCESS IN THE COMPANY'S CLASS COST OF SERVICE STUDY.

A29. The purpose of any Class Cost of Service Study ("CCOSS") is to arrive at the cost of serving each customer class and present a systematic approach to allocating this cost (or total revenue requirement) to the different classes of customers. The CCOSS then provides a measure of guidance for the TRA to consider how to best adjust individual rates for each customer class to produce the total revenue requirement.

Q30. HAVE YOU REVIEWED THE COMPANY'S PROPOSED CLASS COST OF SERVICE STUDY IN THIS CASE?

A30. Yes. The Company has developed a CCOSS that classifies each element of rate base and income to its different tariffs using 40 separate allocation factors. The result of the Company's CCOSS is to allocate 0.3% of its proposed $12.1 million rate increase to industrial customers and allocate the remaining 99.7% to all other customers.

Q31. DO YOU AGREE WITH THE COMPANY'S CCOSS METHODOLOGY IN THIS CASE?

A31. No. The assignment of 40 individual allocation factors to each element of the Company's cost of service is inherently judgmental, and the Company has not introduced any evidence to fully explain its rationale for each individual allocation assignment. For example, the Company has allocated a significant portion of its costs based upon peak day consumption, meaning that almost all of these costs will be allocated to residential and commercial customers without any discussion or evidence as to why such an allocation is appropriate. I could easily justify allocating many of these same costs based upon the total throughput of each customer class which would then allocate a majority of the costs to industrial customers. Since the Company has not provided any rationale for its individual allocation choices it is impossible to determine its rationale for cost allocation.

Finally, other factors beyond just the cost of service need to also be considered in allocating costs. These other factors include value of service, product marketability, encouragement of efficient use of facilities, broad availability of service functions, and a fair distribution of charges among users. Since it is impossible to properly consider each of these other factors, it follows that no mechanical or mathematical formula can ever be applied to the cost of service that would translate it directly into rates.

Q32. HAS THE TRA EVER ADOPTED A CCOSS FOR THE PURPOSE OF SETTING RATES?

A32. No. To my knowledge, the TRA has never adopted a CCOSS for any of the utilities that it regulates.

Q33. HOW DO YOU PROPOSE THAT THE TRA ALLOCATE THE COMPANY'S REVENUE REQUIREMENTS TO EACH CUSTOMER CLASS?

A33. I would recommend that the revenue deficiency of $6,951,869 be allocated evenly across-the-board to all customer classes, including Street Lighting customers, based upon the ratio of each customer class' attrition period margin to total attrition period margin. My complete revenue deficiency allocation is presented on CPAD Exhibit, Schedule 12 and summarized below on Table 6.

Table 6 – CAPD Attrition Period Revenue Deficiency Allocation				
Tariff	**Current Margin**	**Revenue Increase**	**Proposed Margin**	**Percent Change**
Residential	$25,283,807	$2,795,476	$28,079,283	11.06%
Small General	1,419,048	156,896	1,575,944	11.06%
Medium General	5,571,262	615,981	6,187,243	11.06%
Large General	8,230,429	909,989	9,140,418	11.06%
Industrial Power	17,424,858	1,926,561	19,351,419	11.06%
Church Service	481,454	53,231	534,685	11.06%
Public School	924,214	102,185	1,026,399	11.06%
Electric Heating	1,340,689	148,232	1,488,921	11.06%
Outdoor Lighting	691,097	76,410	767,507	11.06%
Street Lighting	1,509,602	166,908	1,676,510	11.06%
Electric Margin	**$62,876,460**	**$6,951,869**	**$69,828,329**	**11.06%**
Other Revenues	1,706,023	39,348	1,745,371	2.31%
Total Margin	**$64,582,483**	**$6,991,217**	**$71,573,700**	**10.83%**

To summarize the results of Table 6, the CPAD would allocate an 11.06% increase to residential customers based upon an across-the-board distribution of attrition period margin under current rates. The CPAD believes that an across-the-board increase to all customer classes more equitably spreads the burden of any increase in rates and is preferable to the Company's CCOSS results.

Q34. WHAT IS THE PURPOSE OF THE COMPANY'S PROPOSED RATE REALIGNMENT RIDER?

A34. The Company claims that the current rates result in disparate rates of return among the rate classes. Therefore, the Company has proposed a Rate Realignment Rider in order to "gradually equalize the class rates of return…over a six-year period."[28] In other words, the Company is proposing to annually adjust rates for each of its customer classes over the next six years in order to bring them

[28] Direct testimony of Company witness Castle, page 4, lines 7 – 8.

into what it perceives as some type of rate nirvana. According to the Company's proposal, the Rate Realignment Rider would result in additional annual rate increases for residential customers of between 1.44% and 2.31%[29] after the initial increase in rates from this rate case.

Q35. DO YOUR AGREE WITH THE COMPANY'S PROPOSED RATE REALIGNMENT RIDER?

A35. No. As I mentioned above, I disagree with the Company's proposed CCOSS that calculates the current rate of return for each tariff. Therefore, I also disagree with concept of realigning tariff rates on an annual basis to conform to the return calculated in the CCOSS.

Q36. WHAT SPECIFIC RATE DESIGN DO YOU PROPOSE?

A36. As mentioned above, I recommend that the proposed revenue deficiency of $6,951,870 be allocated evenly across-the-board to all customer classes based upon the ratio of each customer class' attrition period margin to total attrition period margin. As to specific tariff rates, I recognize that the decline in customer usage has impaired the Company's ability to earn a fair rate of return. For that reason, I am proposing a <u>gradual</u> shift towards placing a higher margin on customer charges than through volumetric charges. I am therefore proposing that the entire revenue deficiency in this case be recovered through increased customer charges only. In other words, I would recommend that the existing base rate commodity charges (net of fuel surcharges) remain at their current levels.

[29] Direct testimony of Company witness Buck, page 27, Table 5.

My complete rate design is contained on Attachment WHN-5.

[Testimony continues on next page]

V. POLICY ISSUES

Q37. MR. NOVAK, PLEASE SUMMARIZE THE POLICY PROPOSALS OFFERED BY THE COMPANY.

A37. The Company has made a number of significant policy proposals in its rate case filing. Among these changes are a proposal to include fuel and non-fuel power costs in base rates, changes to the net metering tariff, exclusion of street lighting service from the cost of service, proposed demand side management programs, a Tennessee Reliability Management program, and various miscellaneous changes to the tariff.

Q38. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO INCLUDE FUEL AND NON-FUEL POWER COSTS IN BASE RATES.

A38. The Company's current base rates already include partial recovery of fuel, transmission costs, and purchased power costs.[30] In addition to this base fuel recovery, the Company also has separate riders to recover the difference between actual purchased power cost and the level of power cost in base rates. The Company is now proposing to reflect the current going level amount of generation, transmission and fuel cost in base rates.[31]

Q39. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE GENERATION, TRANSMISSION AND FUEL COSTS IN BASE RATES?

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[30] According to the Company's current tariff, a base fuel cost of 15.8563 mills per KWH adjusted for losses is already included in the KWH rates.
[31] Direct testimony of Company witness Castle, page 3, lines 9 – 22.

A39. No, I do not. In the past, the TRA has allowed the recovery of certain costs in the base rates of gas and electric utilities. For example, at one time gas utilities recovered a portion of their wholesale gas cost, capacity cost and storage cost through base rates. However, over time the TRA has adjusted this methodology where only the distribution costs are included in base rates. The rationale for this change of thought is that since the TRA only regulates the distribution rates, that these are the only rates that should be reflected in the tariff. As a result, any costs relating to gas procurement (or purchased power in this case) are more properly recovered in the purchased gas adjustment.

Since KPC has not filed a rate case since 1992, such a change has never been included in the Company's base rates. I would therefore recommend that only the distribution cost of service be included in the new base rates for KPC. Simultaneous with the implementation of new base rates, the Company will also need make an adjustment to its Fuel Adjustment Clause to recover fuel costs that were previously included in base rates.

Q40. HAS THE COMPANY PROPOSED CHANGES TO ITS NET METERING SERVICE TARIFF?

A40. Yes. The Company has proposed changes to its current Net Metering Service ("NMS") tariff that appear to raise a number of legal issues. I am not an attorney, and I do not express an opinion on the legality or illegality of the Company's proposed change to the NMS tariff. However, it appears to me that the legal threshold issues related to any changes in the NMS tariff need to be adequately addressed before considering any new regulatory policy on this tariff.

Q41. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO EXCLUDE STREET LIGHTING SERVICE FROM THE COST OF SERVICE.

A41. The Company has excluded Street Lighting service from its rate case. According to the Company, Street Lighting service is a separate contract, not a tariff offering, and therefore is excluded from this base case proceeding.[32]

Q42. DO YOU AGREE WITH THE COMPANY'S ASSERTION THAT STREET LIGHTING RATES ARE A SEPARATE CONTRACT AND THEREFORE NOT A PART OF THIS RATE CASE?

A42. No. Even if Street Lighting were a separate contract, it would still need to be considered as a component of this rate case. Instead, the Company is characterizing this service as if it were unregulated. It appears that the Company is currently charging different rates for Street Lighting service depending on whether the customer was taking service before or after January 1, 1995. It is also unclear when these rates were last changed.

Q43. HAS THE COMPANY EVER REQUESTED APPROVAL FROM THE TRA TO CHANGE THE RATES CHARGED TO STREET LIGHTING CUSTOMERS?

[32] Company response to CPAD Data Request 1-23.

A43. No. It does not appear that the Company has ever requested approval from the TRA to change the rates charged to Street Lighting customers.

Q44. WHAT IS YOUR RECOMMENDATION ON SETTING RATES FOR STREET LIGHTING SERVICE?

A44. First, I recommend that the current income and investment from Street Lighting be included in the cost of service as proposed by the CPAD. Next, I would recommend that Street Lighting rates be increased by the same average percentage increase on current margin that I have proposed for all other customers. The details for my proposed rates for Street Lighting customers is contained in Attachment WHN-5, Schedule 10.

Q45. PLEASE DESCRIBE THE COMPANY'S PROPOSED DEMAND SIDE MANAGEMENT PROGRAM.

A45. The Company has proposed two separate Demand Side Management ("DSM") programs that it refers to as a "Residential Direct Load Control Program" and a "Residential Low Income Program". The proposed Residential Direct Load Control Program is designed to reduce residential summer peak demand by cycling off air conditioners and electric heat pumps through the use of separately installed control devices. The proposed Residential Low Income Program aims to generate savings for low income residential customers through an evaluation of energy savings opportunities and weatherization upgrades. The continuing annual cost for both programs is expected to be approximately $300,000.

Q46. DO YOU SUPPORT THE COMPANY'S PROPOSED COST RECOVERY FOR THESE PROGRAMS?

A46. No. I am opposed to cost recovery for both of the Company's proposed programs. Both of these programs would essentially amount to an involuntary tax on electric consumers, with the proceeds from that involuntary tax funding the two programs. The Company does not establish that either of the programs is necessary in order to provide utility service. In addition, the programs violate the state's conservation policy on "cost effective, measurable and verifiable savings"[33] since they require all of the Company's 47,000 customers to pay for the benefits received by as few as 300 customers.[34] I therefore recommend that the TRA reject both of the Company's demand side management proposals from cost recovery.

Q47. PLEASE DESCRIBE THE COMPANY'S PROPOSED TENNESSEE RELIABILITY MANAGEMENT RIDER.

A47. The Company's proposed Tennessee Reliability Management Rider is meant to address the incremental cost of vegetation management or "tree trimming" beyond the historical levels included in the Company's filing. The Company's projected cost from this program is approximately $2,000,000 which is discussed in more detail in Mr. Smith's testimony.

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[33] Section 53 of Public Chapter 531.

[34] Testimony of Company witness Castle, Page 8, Figure 1.

Q48. DO YOU AGREE WITH THE COMPANY'S PROPOSAL FOR ITS PROPOSED TENNESSEE RELIABILITY MANAGEMENT RIDER?

A48. No, I do not. The rate case already includes a going level amount for tree trimming expenses. I certainly cannot find where the Company has supported such a material increase in rates to justify this increase.[35]

Q49. ARE THERE ANY OTHER POLICY ISSUES THAT NEED TO BE ADDRESSED BY THE TRA THAT WERE NOT PROPOSED BY THE COMPANY?

A49. Yes. The Company presently has a surcharge for the TRA fee in its tariff that is designed to recover the difference between the amount in base rates and the current cost. No other Tennessee utility has such a rider and I would recommend that it be removed from KPC's tariff. My proposed rate design on Attachment WHN-5 appropriately excludes this rider.

VI. MISCELLANEOUS TARIFF CHANGES

Q50. MR. NOVAK, HAVE YOU REVIEWED THE MISCELLANEOUS TARIFF RATE CHANGES PROPOSED BY THE COMPANY?

A50. Yes. In this case, the Company has proposed several changes to its existing tariff for miscellaneous rates.[36] The changes to the tariff for miscellaneous rates includes a proposed change in the bad check charge from $7.50 to $12.50, a new

[35] The Company's entire justification on this issue appears to be contained within the direct testimony of witnesses Philip Wright, pages 9 – 12 and Isaac Webb, page 4.

[36] See specifically the pre-filed direct testimony of Company witnesses Simmons and Caudill.

proposal for a deposit requirement of $15.00 and $30.00 for meter tests, and an increase in the reconnection charge from $16.00 to $50.00. These rate changes appear to be in line with rates charged by other utilities, and I would recommend that the TRA consider them for KPC.

Q51. WHAT CHANGES HAS THE COMPANY PROPOSED TO THE TERMS AND CONDITIONS OF SERVICE IN ITS CURRENT TARIFF?

A51. The Company has proposed several changes to the terms and conditions of its current tariff. Among these are changes to the definitions, metering and billing, service connections, domestic service, change of address by the customer, meter accuracy tests, denial and discontinuance of service, equipment installation surcharges, and contributions in aid of construction taxability.

Q52. DO YOU AGREE WITH THE PROPOSED CHANGES FOR THE TERMS AND CONDITIONS OF SERVICE THAT THE COMPANY HAS INCLUDED IN THE TARIFF?

A52. Only in part. I disagree with the Company's proposals for Service Connections, Domestic Service, Equipment Installation Surcharges and Contribution in Aid of Construction Taxability. I have reviewed the Company's other proposed changes for the remainder of their tariff, and I do not have any disagreement with these other proposals at this time.

Q53. PLEASE DESCRIBE THE CHANGES TO THE TARIFF TERMS AND CONDITIONS RELATED TO SERVICE CONNECTIONS.

A53. The Company has added new language to this section of its tariff requiring the customer to obtain their own easements for receiving electric service. The specific new language that the Company is proposing for Service Connections is as follows:

"The Company shall not be required to obtain easements or permits over or under the property of another necessary for service if the terms thereof are unduly burdensome."

Q54. DO YOU AGREE WITH THIS PROPOSED PROVISION FOR SERVICE CONNECTIONS?

A54. No, I do not. The Company has a pre-existing obligation to provide utility service to customers in its territory. It is doubtful that individual customers, especially residential customers, would have the expertise to remedy a problematic easement issue. Since the Company has eminent domain as well as franchise authority in its certificated area, this should normally not pose a problem for easement issues. In addition, the Company has not provided any evidence in its filing that easement and right-of-way authority is an issue that presently needs to be addressed. I would therefore recommend that the TRA reject the Company's proposed changes to its terms and conditions related to Service Connections.

Q55. PLEASE DESCRIBE THE CHANGES TO THE TARIFF TERMS AND CONDITIONS RELATED TO DOMESTIC SERVICE.

A55. The Company has added new language to this section of its tariff requiring that any commercial activity occurring within a residential premise be separately metered.

Q56. DO YOU AGREE WITH THIS PROPOSED PROVISION FOR DOMESTIC SERVICE?

A56. No, I do not. The Company has not provided any evidence in its filing that commercial activity within residences is an issue that presently needs to be addressed. In addition, the Company provides no testimony for exactly how such a provision would be generally enforced. I would therefore recommend that the TRA reject the Company's proposed changes to its terms and conditions related to Domestic Service.

Q57. PLEASE DESCRIBE THE CHANGES TO THE TARIFF TERMS AND CONDITIONS RELATED TO EQUIPMENT INSTALLATION SURCHARGES.

A57. The Company has proposed to revised the existing tariff language related to Equipment Installation Surcharges. Currently, the Company's tariff requires a monthly facility charge equal to 1.13% of additional costs. The Company has proposed to change this monthly surcharge to 1.08% of additional costs.

Q58. DO YOU AGREE WITH THIS PROPOSED CHANGE TO EQUIPMENT INSTALLATION SURCHARGES?

A58. No, I do not. At this point, the Company has not provided any data supporting either continuing the existing monthly surcharge of 1.13% or the proposed monthly surcharge of 1.08%. I would therefore recommend to the TRA that any Equipment Installation Surcharge be denied until adequate supporting data is provided.

Q59. PLEASE DESCRIBE THE CHANGES TO THE TARIFF TERMS AND CONDITIONS RELATED TO CONTRIBUTIONS IN AID OF CONSTRUCTION ("CIAOC") TAXABILITY.

A59. The Company has proposed to revise the existing tariff language related to CIAOC taxability. In those cases, when the Company's customers are required to pay either all or a portion of the equipment cost for new service, these payments are treated as taxable income. Currently, the Company's tariff requires all CIAOC payments in excess of $100,000 to be grossed up by 35% to cover their required tax payment. The Company is now proposing that all CIAOC payments of any amount be adjusted to cover their required tax payment.

Q60. DO YOU AGREE WITH THIS PROPOSED PROVISION FOR CIAOC?

A60. No, I do not. I am concerned that the application of such a tax requirement for relatively small CIAOC payments from residential customers could make such additions difficult to afford. In addition, the Company has not provided any evidence in its filing that CIAOC activity is an issue that presently needs to be addressed. I would therefore recommend that the TRA reject the Company's proposed changes to its terms and conditions related to CIAOC Taxability.

Q61. DOES THIS COMPLETE YOUR TESTIMONY?

A61. Yes, it does. However, I reserve the right to incorporate any new data that may subsequently become available.

ATTACHMENT WHN-1
William H. Novak Vitae

William H. Novak
19 Morning Arbor Place
The Woodlands, TX 77381

Phone: 713-298-1760
Email: halnovak@whnconsulting.com

Areas of Specialization

Over twenty-five years of experience in regulatory affairs and forecasting of financial information in the rate setting process for electric, gas, water and wastewater utilities. Presented testimony and analysis for state commissions on regulatory issues in four states and has presented testimony before the FERC on electric issues.

Relevant Experience

WHN Consulting – September 2004 to Present
In 2004, established WHN Consulting to provide utility consulting and expert testimony for energy and water utilities. Complete needs consultant to provide the regulatory and financial expertise that enabled a number of small gas and water utilities to obtain their Certificate of Public Convenience and Necessity (CCN) that included forecasting the utility investment and income. Also provided the complete analysis and testimony for utility rate cases including revenues, operating expenses, taxes, rate base, rate of return and rate design for utilities in Tennessee. Assisted American Water Works Company in preparing rate cases in Ohio and Iowa. Provided commercial and industrial tariff analysis and testimony for an industrial intervenor group in a large gas utility rate case. Industry spokesman for water utilities dealing with utility commission rulemaking. Consultant for the North Carolina and Illinois Public Utility Commissions in carrying out their oversight functions of Duke Energy and Peoples Gas Light and Coke Company through focused management audits. Also provide continual utility accounting services and preparation of utility commission annual reports for water and gas utilities.

Sequent Energy Management – February 2001 to July 2003
Vice-President of Regulatory Compliance for approximately two years with Sequent Energy Management, a gas trading and optimization affiliate of AGL Resources. In that capacity, directed the duties of the regulatory compliance department, and reviewed and analyzed all regulatory filings and controls to ensure compliance with federal and state regulatory guidelines. Engaged and oversaw the work of a number of regulatory consultants and attorneys in various states where Sequent has operations. Identified asset management opportunities and regulatory issues for Sequent in various states. Presented regulatory proposals and testimony to eliminate wholesale gas rate fluctuations through hedging of all wholesale gas purchases for utilities. Also prepared testimony to allow gas marketers to compete with utilities for the transportation of wholesale gas to industrial users.

Atlanta Gas Light Company – April 1999 to February 2001

Director of Rates and Regulatory Analysis for approximately two years with AGL Resources, a public utility holding company serving approximately 1.9 million customers in Georgia, Tennessee, and Virginia. In that capacity, was instrumental in leading Atlanta Gas Light Company through the most complete and comprehensive gas deregulation process in the country that involved terminating the utility's traditional gas recovery mechanism and instead allowing all 1.5 million AGL Resources customers in Georgia to choose their own gas marketer. Also responsible for all gas deregulation filings, as well as preparing and defending gas cost recovery and rate filings. Initiated a weather normalization adjustment in Virginia to track adjustments to company's revenues based on departures from normal weather. Analyzed the regulatory impacts of potential acquisition targets.

Tennessee Regulatory Authority – Aug. 1982 to Apr 1999; Jul 2003 to Sep 2004

Employed by the Tennessee Regulatory Authority (formerly the Tennessee Public Service Commission) for approximately 19 years, culminating as Chief of the Energy and Water Division. Responsible for directing the division's compliance and rate setting process for all gas, electric, and water utilities. Either presented analysis and testimony or advised the Commissioners/Directors on policy setting issues, including utility rate cases, electric and gas deregulation, gas cost recovery, weather normalization recovery, and various accounting related issues. Responsible for leading and supervising the purchased gas adjustment (PGA) and gas cost recovery calculation for all gas utilities. Responsible for overseeing the work of all energy and water consultants hired by the TRA for management audits of gas, electric and water utilities. Implemented a weather normalization process for water utilities that was adopted by the Commission and adopted by American Water Works Company in regulatory proceedings outside of Tennessee.

Education

B.A, Accounting, Middle Tennessee State University, 1981
MBA, Middle Tennessee State University, 1997

Professional

Certified Public Accountant (CPA), Tennessee Certificate # 7388
Certified Management Accountant (CMA), Certificate # 7880
Former Vice-Chairman of National Association of Regulatory Utility Commission's Subcommittee on Natural Gas

WHN CONSULTING

Witness & Advisory History for William H. Novak, CPA
Selected Cases

State	Company/Sponsor	Year	Assignment	Docket
Louisiana	CenterPoint Energy/Louisiana PSC	2011	Audit of PGA Filings from 2002 - 2008 of CenterPoint Arkla	S-32534
	CenterPoint Energy/Louisiana PSC	2011	Audit of PGA Filings from 2002 - 2008 of CenterPoint Entex	S-32537
	Louisiana Electric Utilities/Louisiana PSC	2012	Technical Consultant for Impact of Net Meter Subsidy on other Electric Customers	R-31417
Tennessee	Aqua Utilities	2006	Rate Case Audit - Revenue, Expenses, Rate Base and Rate Design	06-00187
	Atmos Energy Corporation/Atmos Intervention Group	2006	Rate design for Industrial Intervenor Group	05-00258
	Atmos Energy Corporation/Atmos Intervention Group	2007	Rate design for Industrial Intervenor Group	07-00105
	Bristol TN Essential Services	2009	Audit of Cost Allocation Manual	05-00251
	Chattanooga Manufacturers Association	2009	Spokesperson for Industrial Natural Gas Users before the Tennessee State Legislature	HB-1349
	Tennessee-American Water Company/Tennessee AG	2011	Rate Case Audit - Weather Normalization Adjustments	10-00189
	Piedmont Natural Gas Company/Tennessee AG	2011	Rate Case Audit - Revenue, Class Cost of Service Study & Rate Design	11-00144
	Lynwood Wastewater Utility/Tennessee AG	2012	Rate Case Audit - Revenue, Class Cost of Service Study & Rate Design	11-00198
	Tennessee-American Water Company/Tennessee AG	2012	Rate Case Audit - Revenues, Rate Base, Class Cost of Service Study and Rate Design	12-00049
	Atmos Energy Corporation/Tennessee AG	2012	Rate Case Audit - Revenues, Rate Base and Rate Design	12-00064
Alabama	Jefferson County (Birmingham) Wastewater/Alabama AG	In Process	Bankruptcy Filing - Allowable Costs and Rate Design	2009-2318
Illinois	Peoples & North Shore Gas Cos./Illinois Commerce Comm.	2007	Management Audit of Gas Purchasing Practices	06-0556
New Mexico	Southwestern Public Service Co./New Mexico PRC	2010	Financial Audit of Fuel Costs for 2009 and 2010	09-00351-UT
New York	National Grid/New York PSC	2011	Audit of Affiliate Relationships and Transactions	10-M-0451
Ohio	Ohio-American Water Company/Ohio Consumers' Counsel	2010	Rate Case Audit - Class Cost of Service and Rate Design	09-0391-WS-AIR
	Vectren Energy Delivery of Ohio/Ohio Consumers' Counsel	2008	Rate Case Audit - Class Cost of Service and Rate Design	07-1080-GA-AIR
	Duke Energy-Ohio/Public Utilities Commission of Ohio	2009	Focused Management Audit of Fuel & Purchased Power (FPP Riders)	07-0723-EL-UNC
Texas	Center Point Energy/Texas AG	2009	Rate Case Audit - Class Cost of Service and Rate Design	GUD 9902
Virginia	Aqua Utilities/PSS Legal Fund	2011	Rate Case Audit - Class Cost of Service and Rate Design	W-218, Sub-319
Washington DC	Washington Gas Light Co./Public Service Comm of DC	2011	Audit of Tariff Rider for Infrastructure Replacement Costs	1027

NOTE: *Click on Docket Number to view testimony/report for each case where available.*

ATTACHMENT WHN-2

CPAD Pro Forma Billing Determinants

Kingsport Power Company
CPAD Pro Forma Billing Determinants

Attachment WHN-2
Schedule 1

Line No.	Tariff	Test Period	Weather Adjustment	Customer Growth	Attrition Period
	Residential (11, 15, 18, 30, 31 and 51):				
1	Bills	494,910	0	528	495,438
2	KWH	687,148,848	-2,149,630	-4,218,430	680,780,788
	Small General Service (231, 232 and 233):				
3	Bills	42,409	0	1,080	43,489
4	KWH	22,169,786	-61,719	554,098	22,662,165
	Medium General Service (229, 235 and 237):				
5	Bills	16,382	0	-216	16,166
6	KWH	114,784,123	0	4,101,310	118,885,433
	Large General Service (240, 242 and 244):				
7	Bills	2,917	0	0	2,917
8	KWH	241,461,822	0	2,659,357	244,121,179
9	Demand	711,383	0	9,193	720,576
	Industrial Power (322 and 324):				
10	Bills	77	0	0	77
11	KWH	969,274,471	0	124,202	969,398,673
12	Demand	1,460,691	0	0	1,460,691
	Church Service (221):				
13	Bills	2,210	0	-24	2,186
14	KWH	9,872,565	0	-21,583	9,850,982
	Public School (640, 641 and 642):				
15	Bills	367	0	0	367
16	KWH	27,413,430	0	0	27,413,430
	Electric Heating General (208 and 209):				
17	Bills	7,149	0	-192	6,957
18	KWH	25,555,908	-136,210	-677,421	24,742,277
19	Demand	122,710	0	0	122,710
	Outdoor Lighting (93 - 126):				
20	Lamps	65,447	0	216	65,663
	Street Lighting (523):				
21	Lamps	123,243	0	3,719	126,962
22	**Total Bills**	**566,421**	**0**	**1,176**	**567,597**
23	**Total KWH**	**2,097,680,953**	**-2,347,559**	**2,521,533**	**2,097,854,927**
24	**Total Demand**	**2,294,784**	**0**	**9,193**	**2,303,977**
25	**Total Lamps**	**188,690**	**0**	**3,935**	**192,625**

SOURCE: CPAD Revenue Workpaper R-1-1.01.

Kingsport Power Company
Comparison of Company and CPAD Pro Forma Billing Determinants

Attachment WHN-2
Schedule 2

Line No.	Tariff	Company A/	CPAD B/	Difference
	Residential (11, 15, 18, 30, 31 and 51):			
1	Bills	494,854	495,438	-584
2	KWH	681,303,842	680,780,788	523,054
	Small General Service (231, 232 and 233):			
3	Bills	43,216	43,489	-273
4	KWH	21,593,134	22,662,165	-1,069,031
	Medium General Service (229, 235 and 237):			
5	Bills	16,397	16,166	231
6	KWH	108,949,672	118,885,433	-9,935,761
	Large General Service (240, 242 and 244):			
7	Bills	2,891	2,917	-26
8	KWH	231,189,908	244,121,179	-12,931,271
9	Demand	704,214	720,576	-16,362
	Industrial Power (322 and 324):			
10	Bills	72	77	-5
11	KWH	956,231,909	969,398,673	-13,166,764
12	Demand	1,472,404	1,460,691	11,713
	Church Service (221):			
13	Bills	2,206	2,186	20
14	KWH	9,620,101	9,850,982	-230,881
	Public School (640, 641 and 642):			
15	Bills	384	367	17
16	KWH	28,009,418	27,413,430	595,988
	Electric Heating General (208 and 209):			
17	Bills	7,119	6,957	162
18	KWH	25,759,259	24,742,277	1,016,982
19	Demand	11,438	122,710	-111,272
	Outdoor Lighting (93 - 126):			
20	Lamps	65,363	65,663	-300
	Street Lighting (523):			
21	Lamps	113,180	126,962	-13,782
22	**Total Bills**	**567,139**	**567,597**	**-458**
23	**Total KWH**	**2,062,657,243**	**2,097,854,927**	**-35,197,684**
24	**Total Demand**	**2,188,056**	**2,303,977**	**-115,921**
25	**Total Lamps**	**178,543**	**192,625**	**-14,082**

A/ Company response to CPAD DR1-9.
B/ CPAD Attachment WHN-2, Schedule 1.

ATTACHMENT WHN-3
Weather Normalization Calculations

Kingsport Power Company
Total Without Space Heating
Cycle Weather Normalization **2 Variable Regression - Bristol Heating & Cooling Degree Days**

Attachment WHN-3
Schedule 1

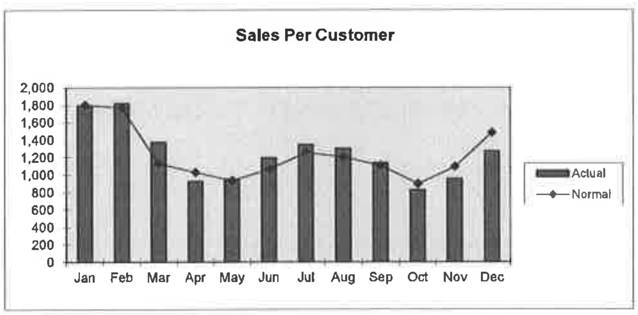
For the 12 Months Ended December 31, 2015

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	BRIS-CDD ACTUAL WEATHER 1	BRIS-CDD NORMAL WEATHER 1	BRIS-HDD ACTUAL WEATHER 2	BRIS-HDD NORMAL WEATHER 2
January, 2015	13,654,726	7,607	1,795	0	0	845	850
February	13,872,518	7,616	1,821	0	0	909	868
March	10,426,662	7,590	1,374	0	0	808	609
April	7,015,089	7,579	926	9	4	318	407
May	7,197,352	7,557	952	56	34	146	170
June	9,016,844	7,539	1,196	232	154	12	38
July	10,160,060	7,540	1,347	332	288	0	1
August	9,802,184	7,535	1,301	369	323	0	0
September	8,573,680	7,557	1,135	250	244	16	5
October	6,270,011	7,580	827	62	52	50	124
November	7,272,202	7,589	958	3	3	321	429
December	9,694,068	7,609	1,274	0	0	496	665
TOTAL	**112,955,396**	**90,898**	**14,907**	**1,313**	**1,102**	**3,921**	**4,167**

MONTH	WEATHER 1 DEVIATION	WEATHER 2 DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
January, 2015	0	5	6.7486	1,802	13,706,063	51,337
February	0	-41	-50.6765	1,771	13,486,566	-385,952
March	0	-199	-246.0001	1,128	8,559,521	-1,867,141
April	-5	89	100.5411	1,026	7,777,090	762,001
May	-22	24	-17.1049	935	7,068,090	-129,262
June	-78	26	-133.2486	1,063	8,012,283	-1,004,561
July	-44	1	-92.2334	1,255	9,464,620	-695,440
August	-46	0	-95.9803	1,205	9,078,972	-723,212
September	-6	-11	-26.0903	1,108	8,376,516	-197,164
October	-10	74	69.6424	897	6,797,900	527,889
November	0	108	133.4099	1,092	8,284,650	1,012,448
December	0	169	209.7765	1,484	11,290,257	1,596,189
TOTAL	**-211**	**246**	**-141.2156**	**14,765**	**111,902,528**	**-1,052,868**

Regression Output:

Constant	605.3890
Std Err of Y Est	113.6720
R Squared	0.8966
X Coefficient1	2.1156
X Coefficient2	1.2406
Std Err of Coef.1	0.3482
Std Err of Coef.2	0.1406



Kingsport Power Company
Total With Space Heating
Cycle Weather Normalization — 2 Variable Regression - Bristol Heating & Cooling Degree Days

Attachment WHN-3
Schedule 2

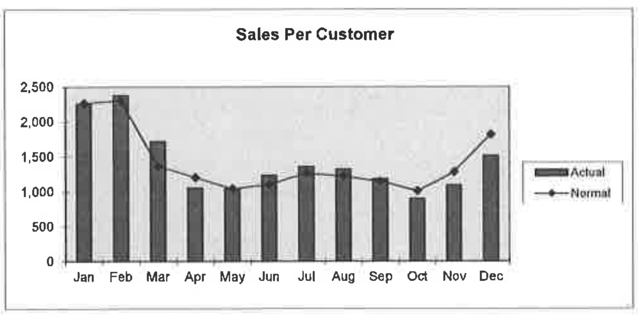
For the 12 Months Ended December 31, 2015

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	BRIS-CDD ACTUAL WEATHER 1	BRIS-CDD NORMAL WEATHER 1	BRIS-HDD ACTUAL WEATHER 2	BRIS-HDD NORMAL WEATHER 2
January, 2015	76,164,737	33,749	2,257	0	0	845	850
February	80,347,699	33,782	2,378	0	0	909	868
March	57,889,181	33,699	1,718	0	0	808	609
April	35,475,237	33,629	1,055	9	4	318	407
May	35,115,876	33,594	1,045	56	34	146	170
June	41,350,202	33,596	1,231	232	154	12	38
July	45,686,352	33,636	1,358	332	288	0	1
August	44,418,559	33,644	1,320	369	323	0	0
September	39,655,160	33,604	1,180	250	244	16	5
October	30,261,300	33,632	900	62	52	50	124
November	36,691,092	33,673	1,090	3	3	321	429
December	51,138,057	33,774	1,514	0	0	496	665
TOTAL	574,193,452	404,012	17,046	1,313	1,102	3,921	4,167

MONTH	WEATHER 1 DEVIATION	WEATHER 2 DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
January, 2015	0	5	9.6564	2,266	76,490,631	325,894
February	0	-41	-72.5115	2,306	77,898,116	-2,449,583
March	0	-199	-352.1543	1,366	46,021,933	-11,867,248
April	-5	89	147.8190	1,203	40,446,242	4,971,005
May	-22	24	-6.8493	1,038	34,885,781	-230,095
June	-78	26	-128.2024	1,103	37,043,114	-4,307,088
July	-44	1	-96.6745	1,262	42,434,609	-3,251,743
August	-46	0	-100.7861	1,219	41,027,711	-3,390,848
September	-6	-11	-32.8213	1,147	38,552,233	-1,102,927
October	-10	74	107.9653	1,008	33,892,389	3,631,089
November	0	108	191.2207	1,281	43,130,067	6,438,975
December	0	169	300.1068	1,814	61,273,864	10,135,807
TOTAL	-211	246	-33.2312	17,013	573,096,690	-1,096,762

Regression Output:

Constant	596.9513
Std Err of Y Est	151.1721
R Squared	0.9170
X Coefficient1	2.2260
X Coefficient2	1.7751
Std Err of Coef.1	0.4631
Std Err of Coef.2	0.1870



Kingsport Power Company
SGS Total
Cycle Weather Normalization — 2 Variable Regression - Bristol Heating & Cooling Degree Days

Attachment WHN-3
Schedule 3

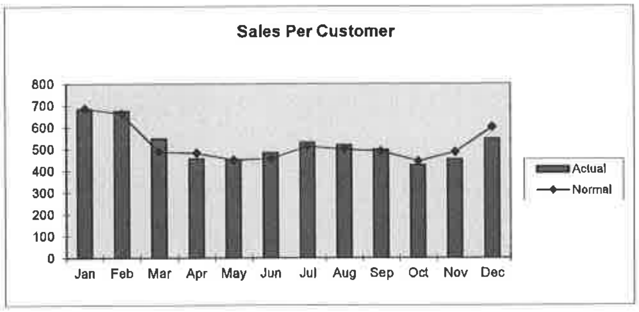
For the 12 Months Ended December 31, 2015

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	BRIS-CDD ACTUAL WEATHER 1	BRIS-CDD NORMAL WEATHER 1	BRIS-HDD ACTUAL WEATHER 2	BRIS-HDD NORMAL WEATHER 2
January, 2015	2,394,448	3,497	685	0	0	845	850
February	2,363,127	3,500	675	0	0	909	868
March	1,924,476	3,506	549	0	0	808	609
April	1,601,834	3,516	456	9	4	318	407
May	1,585,356	3,506	452	56	34	146	170
June	1,721,127	3,550	485	232	154	12	38
July	1,874,188	3,521	532	332	288	0	1
August	1,848,397	3,555	520	369	323	0	0
September	1,759,747	3,543	497	250	244	16	5
October	1,511,786	3,549	426	62	52	50	124
November	1,615,533	3,566	453	3	3	321	429
December	1,969,767	3,600	547	0	0	496	665
TOTAL	**22,169,786**	**42,409**	**6,276**	**1,313**	**1,102**	**3,921**	**4,167**

MONTH	WEATHER 1 DEVIATION	WEATHER 2 DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
January, 2015	0	5	1.6984	686	2,400,387	5,939
February	0	-41	-12.7537	662	2,318,489	-44,638
March	0	-199	-61.9262	487	1,707,363	-217,113
April	-5	89	25.6878	481	1,692,152	90,318
May	-22	24	-2.5914	450	1,576,271	-9,085
June	-78	26	-27.4631	457	1,623,633	-97,494
July	-44	1	-19.7809	513	1,804,539	-69,649
August	-46	0	-20.6024	499	1,775,155	-73,242
September	-6	-11	-6.1277	491	1,738,037	-21,710
October	-10	74	18.3352	444	1,576,858	65,072
November	0	108	33.6071	487	1,735,376	119,843
December	0	169	52.7888	600	2,159,807	190,040
TOTAL	**-211**	**246**	**-19.1281**	**6,257**	**22,108,067**	**-61,719**

Regression Output:

Constant	371.2904
Std Err of Y Est	33.9632
R Squared	0.8646
X Coefficient1	0.4546
X Coefficient2	0.3122
Std Err of Coef.1	0.1040
Std Err of Coef.2	0.0420



Kingsport Power Company
EHG-Minimum (209)
Cycle Weather Normalization **2 Variable Regression - Bristol Heating & Cooling Degree Days**

Attachment WHN-3
Schedule 4

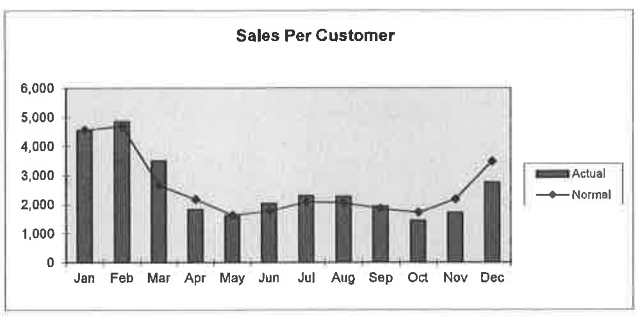
For the 12 Months Ended December 31, 2015

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	BRIS-CDD ACTUAL WEATHER 1	BRIS-CDD NORMAL WEATHER 1	BRIS-HDD ACTUAL WEATHER 2	BRIS-HDD NORMAL WEATHER 2
January, 2015	640,187	141	4,540	0	0	845	850
February	684,380	141	4,854	0	0	909	868
March	493,240	141	3,498	0	0	808	609
April	258,126	142	1,818	9	4	318	407
May	231,098	142	1,627	56	34	146	170
June	288,658	142	2,033	232	154	12	38
July	321,052	140	2,293	332	288	0	1
August	318,039	140	2,272	369	323	0	0
September	271,542	141	1,926	250	244	16	5
October	200,023	138	1,449	62	52	50	124
November	245,110	143	1,714	3	3	321	429
December	386,093	140	2,758	0	0	496	665
TOTAL	**4,337,548**	**1,691**	**30,782**	**1,313**	**1,102**	**3,921**	**4,167**

MONTH	WEATHER 1 DEVIATION	WEATHER 2 DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
January, 2015	0	5	23.1061	4,563	643,445	3,258
February	0	-41	-173.5081	4,680	659,915	-24,465
March	0	-199	-842.7250	2,655	374,416	-118,824
April	-5	89	355.6291	2,173	308,625	50,499
May	-22	24	-7.8267	1,620	229,987	-1,111
June	-78	26	-276.4249	1,756	249,406	-39,252
July	-44	1	-214.1779	2,079	291,067	-29,985
August	-46	0	-223.4090	2,048	286,762	-31,277
September	-6	-11	-76.3448	1,849	260,777	-10,765
October	-10	74	262.3831	1,712	236,232	36,209
November	0	108	457.7191	2,172	310,564	65,454
December	0	169	718.0788	3,476	486,624	100,531
TOTAL	**-211**	**246**	**2.4998**	**30,785**	**4,337,820**	**272**

Regression Output:

Constant	637.1315
Std Err of Y Est	308.8457
R Squared	0.9400
X Coefficient1	4.9372
X Coefficient2	4.2474
Std Err of Coef.1	0.9462
Std Err of Coef.2	0.3821



Kingsport Power Company
EHG-Regular (208)
Cycle Weather Normalization **2 Variable Regression - Bristol Heating & Cooling Degree Days**

Attachment WHN-3
Schedule 5

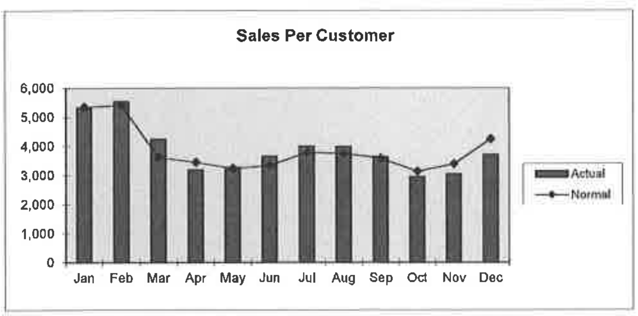
For the 12 Months Ended December 31, 2015

MONTH	SALES	CUSTOMERS	SALES PER CUSTOMER	BRIS-CDD ACTUAL WEATHER 1	BRIS-CDD NORMAL WEATHER 1	BRIS-HDD ACTUAL WEATHER 2	BRIS-HDD NORMAL WEATHER 2
January, 2015	2,485,395	466	5,333	0	0	845	850
February	2,533,654	457	5,544	0	0	909	868
March	1,939,899	456	4,254	0	0	808	609
April	1,454,398	456	3,189	9	4	318	407
May	1,484,536	453	3,277	56	34	146	170
June	1,659,384	454	3,655	232	154	12	38
July	1,809,014	452	4,002	332	288	0	1
August	1,801,807	452	3,986	369	323	0	0
September	1,648,225	452	3,647	250	244	16	5
October	1,339,727	454	2,951	62	52	50	124
November	1,374,434	451	3,048	3	3	321	429
December	1,687,887	455	3,710	0	0	496	665
TOTAL	**21,218,360**	**5,458**	**46,597**	**1,313**	**1,102**	**3,921**	**4,167**

MONTH	WEATHER 1 DEVIATION	WEATHER 2 DEVIATION	PER CUST ADJUSTMENT	NORMAL SALE/CUST	NORMAL SALES	WEATHER ADJUSTMENT
January, 2015	0	5	17.2890	5,351	2,493,452	8,057
February	0	-41	-129.8262	5,414	2,474,323	-59,331
March	0	-199	-630.2765	3,624	1,652,493	-287,406
April	-5	89	259.0230	3,448	1,572,512	118,114
May	-22	24	-37.3593	3,240	1,467,612	-16,924
June	-78	26	-318.4682	3,337	1,514,799	-144,585
July	-44	1	-223.3490	3,779	1,708,060	-100,954
August	-46	0	-232.4900	3,754	1,696,722	-105,085
September	-6	-11	-65.1863	3,581	1,618,761	-29,464
October	-10	74	181.4626	3,132	1,422,111	82,384
November	0	108	341.8980	3,389	1,528,630	154,196
December	0	169	537.3976	4,247	1,932,403	244,516
TOTAL	**-211**	**246**	**-299.8853**	**46,297**	**21,081,878**	**-136,482**

Regression Output:

Constant	2,283.7023
Std Err of Y Est	316.1491
R Squared	0.8813
X Coefficient1	5.1262
X Coefficient2	3.1781
Std Err of Coef.1	0.9685
Std Err of Coef.2	0.3911



ATTACHMENT WHN-4

Revenue & Margin Comparison

Kingsport Power Company
Attrition Period Revenue Comparison

Attachment WHN-4
Schedule 1

Line No.	Customer Class	Company	CPAD	Adjustment
1	Residential Service	$59,442,780	$57,600,039	$1,842,741
2	Small General Service	2,365,884	2,385,293	-19,409
3	Medium General Service	10,504,269	11,040,457	-536,188
4	Large General Service	19,657,936	19,663,638	-5,702
5	Industrial Power	57,804,203	54,288,484	3,515,719
6	Chruch Service	952,823	947,307	5,516
7	Public School Service	2,267,020	2,121,121	145,899
8	Electric Heating General Service	2,443,736	2,472,814	-29,078
9	Outdoor Lighting Service	722,983	738,080	-15,097
10	Street Lighting Service	1,448,049	1,509,602	-61,553
11	**Total Electric Service**	**$157,609,683**	**$152,766,835**	**$4,842,848**
12	Other Revenues	1,805,660	1,495,494	310,166
13	**Total Revenue**	**$159,415,343**	**$154,262,329**	**$5,153,014**
14	Less Purchased Power Expense	141,108,293	134,569,031	6,539,262
15	**Gross Margin**	**$18,307,050**	**$19,693,298**	**-$1,386,248**

SOURCE: CPAD Revenue Workpaper R-1-1.02.

ATTACHMENT WHN-5
CPAD Proposed Rate Design

Kingsport Power Company
CPAD Proposed Rate Design
Residential Service

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Residential:									
Regular Residential (Tariff Code 15):									
Service Charge (Bills)	494,066	$7.3000000		$7.3000000	$3,606,682	$3,004,385	$6,611,067	$13.3800000	83.30%
Energy Charge (KWH)	678,741,626	0.0487300	$0.0158563	0.0328737	22,312,749		22,312,749	0.0328737	0.00%
Total Regular Residential (Tariff Code 15)					**$25,919,430**	**$3,004,385**	**$28,923,815**		**11.59%**
Employee Residential (Tariff Code 18)									
Service Charge (Bills)	1,095	7.3000000		7.3000000	$7,994	$6,659	$14,652	$13.3800000	83.30%
Energy Charge (KWH)	1,650,643	0.0414200	0.0158563	0.0255637	42,197		42,197	0.0255637	0.00%
Total Employee Residential (Tariff Code 18)					**$50,190**	**$6,659**	**$56,849**		**13.27%**
Regular Load Management Residential (Tariff Code 11)									
Service Charge (Bills)	218	7.3000000		7.3000000	$1,591	$1,326	$2,917	$13.3800000	83.30%
Energy Charge (KWH)	275,925	0.0487300	0.0158563	0.0328737	9,071		9,071	0.0328737	0.00%
Energy Charge (Last 250 KWH per Month)	52,604	0.0275500	0.0158563	0.0116937	615		615	0.0116937	0.00%
Total Regular Load Management Residential (Tariff Code 11)					**$11,277**	**$1,326**	**$12,603**		**11.76%**
Employee Load Management Residential (Tariff Code 51)									
Service Charge (Bills)	12	7.3000000		7.3000000	$88	$73	$161	$13.3800000	83.30%
Energy Charge (KWH)	14,413	0.0414200	0.0158563	0.0255637	368		368	0.0255637	0.00%
Energy Charge (Last 250 KWH per Month)	3,000	0.0487300	0.0158563	0.0328737	99		99	0.0328737	0.00%
Total Employee Load Management Residential (Tariff Code 51)					**$555**	**$73**	**$628**		**13.16%**
Regular Time of Day Residential (Tariff Codes 30 and 31)									
Service Charge (Bills)	47	13.5000000		13.5000000	$635	$529	$1,163	$24.7500000	83.30%
Energy Charge - On Peak (KWH)	60,461	0.0754100	0.0158563	0.0595537	3,601		3,601	0.0595537	0.00%
Energy Charge - Off Peak (KWH)	37,720	0.0275500	0.0158563	0.0116937	441		441	0.0116937	0.00%
Total Regular Time of Day Residential (Tariff Codes 30 and 31)					**$4,676**	**$529**	**$5,205**		**11.30%**
Total Base Residential Margin					**$25,986,129**	**$3,012,971**	**$28,999,099**		11.59%
TRA Inspection Fee Rider Surcharge					174,923	-174,923	0		-100.00%
Prompt Payment Discount					-877,239	-42,571	-919,810		4.85%
Net Base Residential Margin	**495,438**				**$25,283,813**	**$2.795,477**	**$28,079,290**		**11.06%**
	680,836,392								

SOURCE: CPAD Revenue Workpaper R-10-1.01 and CPAD Exhibit, Schedule 12.

Kingsport Power Company
CPAD Proposed Rate Design
Small General Service

Attachment WHN-5
Schedule 2

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Small General Service:									
SGS-Fixed (Tariff Code 231):									
Service Charge (Bills)	40,037	$8.8000000		$8.8000000	$352,326	$153,309	$505,635	$12.6300000	43.51%
Energy Charge - First 600 KWH per Month	11,629,899	0.0679200	$0.0158563	0.0520637	605,496		605,496	0.0520637	0.00%
Energy Charge - Over 600 KWH per Month	8,743,442	0.0564300	0.0158563	0.0405737	354,754		354,754	0.0405737	0.00%
Total SGS-Fixed					**$1,312,575**	**$153,309**	**$1,465,884**		**11.68%**
SGS-Measured (Tariff Code 232):									
Service Charge (Bills)	2,837	8.8000000		8.8000000	$24,966	$10,863	$35,829	$12.6300000	43.51%
Energy Charge - First 600 KWH per Month	1,020,336	0.0679200	0.0158563	0.0520637	53,122		53,122	0.0520637	0.00%
Energy Charge - Over 600 KWH per Month	1,152,389	0.0564300	0.0158563	0.0405737	46,757		46,757	0.0405737	0.00%
Total SGS-Measured					**$124,845**	**$10,863**	**$135,708**		**8.70%**
SGS-Non Metered (Tariff Code 233):									
Service Charge (Bills)	615	8.8000000		8.8000000	$5,412	$2,355	$7,767	$12.6300000	43.51%
Energy Charge - First 600 KWH per Month	51,043	0.0679200	0.0158563	0.0520637	2,657		2,657	0.0520637	0.00%
Energy Charge - Over 600 KWH per Month	65,056	0.0564300	0.0158563	0.0405737	2,640		2,640	0.0405737	0.00%
Total SGS-Non Metered					**$10,709**	**$2,355**	**$13,064**		**21.99%**
Total Base Small General Service Margin					**$1,448,129**	**$166,528**	**$1,614,657**		11.50%
TRA Inspection Fee Rider Surcharge					7,243	-7,243	0		-100.00%
Prompt Payment Discount					-36,324	-2,389	-38,713		6.58%
Net Base Small General Service Margin	**43,489**				**$1,419,048**	**$156,896**	**$1,575,943**		**11.06%**
	22,662,165								

SOURCE: CPAD Revenue Workpaper R-20-1.01 and CPAD Exhibit, Schedule 12.

Kingsport Power Company
CPAD Proposed Rate Design
Medium General Service

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Medium General Service:									
MGS-Secondary (Tariff Code 235):									
Service Charge (Bills)	16,060	$21.5000000		$21.5000000	$345,290	$647,752	$993,042	$61.8300000	187.60%
Energy Charge - Step 1	74,723,930	0.0737400	$0.0158563	0.0578837	4,325,298		4,325,298	0.0578837	0.00%
Energy Charge - Step 2	39,777,878	0.0368900	0.0158563	0.0210337	836,676		836,676	0.0210337	0.00%
Total MGS Secondary					**$5,507,263**	**$647,752**	**$6,155,015**		**11.76%**
MGS-Primary (Tariff Code 237):									
Service Charge (Bills)	49	93.8500000		93.8500000	$4,599	$8,627	$13,226	$269.9100000	187.60%
Energy Charge - Step 1	2,840,698	0.0686400	0.0158563	0.0527837	149,943		149,943	0.0527837	0.00%
Energy Charge - Step 2	1,065,152	0.0328000	0.0158563	0.0169437	18,048		18,048	0.0169437	0.00%
MGS-Primary					**$172,589**	**$8,627**	**$181,216**		**5.00%**
MGS-Time of Day (Tariff Code 229):									
Service Charge (Bills)	57	23.4500000		23.4500000	$1,337	$2,508	$3,844	$67.4400000	187.60%
Energy Charge - On Peak	313,350	0.0884700	0.0158563	0.0726137	22,754		22,754	0.0726137	0.00%
Energy Charge - Off Peak	164,425	0.0275500	0.0158563	0.0116937	1,923		1,923	0.0116937	0.00%
Total MGS Time of Day					**$26,013**	**$2,508**	**$28,520**		**9.64%**
Total Base Medium General Service Margin					**$5,705,865**	**$658,886**	**$6,364,751**		11.55%
TRA Inspection Fee Rider Surcharge					33,525	-33,525	0		-100.00%
Prompt Payment Discount					-168,129	-9,380	-177,509		5.58%
Net Base Medium General Service Margin	**16,166**				**$5,571,261**	**$615,981**	**$6,187,242**		**11.06%**
	118,885,433								

SOURCE: CPAD Revenue Workpaper R-21-1.01 and CPAD Exhibit, Schedule 12.

Kingsport Power Company
CPAD Proposed Rate Design
Large General Service

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Large General Service:									
LGS-Secondary (Tariff Code 240):									
Service Charge (Bills)	2,791	$77.8500000		$77.8500000	$217,279	$914,147	$1,131,426	$405.3800000	420.72%
Energy Charge (KWH)	226,070,879	0.0386900	$0.0158563	0.0228337	5,162,035		5,162,035	0.0228337	0.00%
Demand Charge (KVA)	655,560	3.7900000		3.7900000	2,484,572		2,484,572	3.7900000	0.00%
Total LGS Secondary					**$7,863,886**	**$914,147**	**$8,778,033**		**11.62%**
LGS-Multi-Secondary (Tariff Code 242):									
Service Charge (Bills)	48	77.8500000		77.8500000	$3,737	$15,722	$19,458	$405.3800000	420.72%
Energy Charge (KWH)	4,590,800	0.0386900	0.0158563	0.0228337	104,825		104,825	0.0228337	0.00%
Demand Charge (KVA)	12,346	3.7900000		3.7900000	46,791		46,791	3.7900000	0.00%
Total LGS-Mulit-Secondary					**$155,353**	**$15,722**	**$171,075**		**10.12%**
LGS-Primary (Tariff Code 244):									
Service Charge (Bills)	78	163.6000000		163.6000000	$12,761	$53,688	$66,449	$851.9000000	420.72%
Energy Charge (KWH)	13,459,500	0.0340100	0.0158563	0.0181537	244,340		244,340	0.0181537	0.00%
Demand Charge (KVA)	52,670	3.6800000		3.6800000	193,826		193,826	3.6800000	0.00%
Total LGS-Primary					**$450,926**	**$53,688**	**$504,614**		**11.91%**
Total Base Large General Service Margin					**$8,470,166**	**$983,556**	**$9,453,722**		11.61%
TRA Inspection Fee Rider Surcharge					59,710	-59,710	0		-100.00%
Prompt Payment Discount					-299,446	-13,858	-313,304		4.63%
Net Base Large General Service Margin	**2,917**				**$8,230,430**	**$909,989**	**$9,140,418**		**11.06%**
	244,121,179								
	720,576								

SOURCE: CPAD Revenue Workpaper R-30-1.01 and CPAD Exhibit, Schedule 12.

Kingsport Power Company
CPAD Proposed Rate Design
Industrial Power Service

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Industrial Power Service:									
IP-Primary (Tariff Code 322):									
Service Charge (Bills)	29	$240.0000000		$240.0000000	$6,960	$148,197	$155,157	$5,350.2400000	2129.27%
Energy Charge (KWH)	85,124,202	0.0230200	$0.0158563	0.0071637	609,804		609,804	0.0071637	0.00%
On-Peak Demand Charge (KW)	145,875	8.7000000		8.7000000	1,269,113		1,269,113	8.7000000	0.00%
Off-Peak Demand Charge (KW)	383	2.5700000		2.5700000	984		984	2.5700000	0.00%
Reactive Charge (KVAR)	1,555	0.7500000		0.7500000	1,166		1,166	0.7500000	0.00%
Total IP-Primary					**$1,888,027**	**$148,197**	**$2,036,224**		**7.85%**
IP-Transmission (Tariff Code 324):									
Service Charge (Bills)	48	1,930.0000000		1,930.0000000	$92,640	$1,972,553	$2,065,193	43,024.8600000	2129.27%
Energy Charge (KWH)	884,274,471	0.0224100	0.0158563	0.0065537	5,795,270		5,795,270	0.0065537	0.00%
On-Peak Demand Charge (KW)	1,314,816	7.6000000		7.6000000	9,992,602		9,992,602	7.6000000	0.00%
Off-Peak Demand Charge (KW)	4,908	1.4000000		1.4000000	6,871		6,871	1.4000000	0.00%
Reactive Charge (KVAR)	141,180	0.7500000		0.7500000	105,885		105,885	0.7500000	0.00%
Backup Reservation Charge - Level A	252,000	0.4200000		0.4200000	105,840		105,840	0.4200000	0.00%
Backup Reservation Charge - Level B	120,000	0.8300000		0.8300000	99,600		99,600	0.8300000	0.00%
Total IP-Transmission					**$16,198,707**	**$1,972,553**	**$18,171,261**		**12.18%**
Total Base Industrial Power Margin					**$18,086,735**	**$2,120,750**	**$20,207,485**		11.73%
TRA Inspection Fee Rider Surcharge					164,851	-164,851	0		-100.00%
Prompt Payment Discount					-826,728	-29,338	-856,066		3.55%
Net Base Industrial Margin	**77**				**$17,424,858**	**$1,926,561**	**$19,351,419**		**11.06%**
	969,398,673								
	1,460,691								
	5,291								
	142,735								
	252,000								
	120,000								

SOURCE: CPAD Revenue Workpaper R-31-1.01 and CPAD Exhibit, Schedule 12.

Kingsport Power Company
CPAD Proposed Rate Design
Church Service

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Church Service:									
Church Service (Tariff Code 221):									
Service Charge (Bills)	2,186	$17.0000000		$17.0000000	$37,162	$56,919	$94,081	$43.0400000	153.16%
Energy Charge (KWH)	9,850,982	0.0621300	$0.0158563	0.0462737	455,841		455,841	0.0462737	0.00%
Total Church Service (Tariff Code 221)					**$493,003**	**$56,919**	**$549,922**		**11.55%**
Total Base Church Service Margin					**$493,003**	**$56,919**	**$549,922**		11.55%
TRA Inspection Fee Rider Surcharge					2,877	-2,877	0		-100.00%
Prompt Payment Discount					-14,426	-811	-15,237		5.62%
Net Base Church Service Margin					**$481,454**	**$53,231**	**$534,686**		**11.06%**

SOURCE: CPAD Revenue Workpaper R-40-1.01 and CPAD Exhibit, Schedule 12.

Kingsport Power Company
CPAD Proposed Rate Design
Public School Service

Attachment WHN-5
Schedule 7

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Public School:									
Public School - Regular (Tariff Code 640):									
Service Charge (Bills)	183	$28.8500000		$28.8500000	$5,280	$54,941	$60,220	$329.0700000	1040.63%
Energy Charge (KWH)	6,991,149	0.0606800	$0.0158563	0.0448237	313,369		313,369	0.0448237	0.00%
Total Public School - Regular					**$318,649**	**$54,941**	**$373,590**		**17.24%**
Public School - Electric Heating Units (Tariff Code 641):									
Service Charge (Bills)	12	28.8500000		28.8500000	$346	$3,603	$3,949	$329.0700000	1040.63%
Energy Charge - Block 1 (KWH)	150,000	0.0606800	0.0158563	0.0448237	6,724		6,724	0.0448237	
Energy Charge - Block 2 (KWH)	769,200	0.0464100	0.0158563	0.0305537	23,502		23,502	0.0305537	0.00%
Total Public School - Electric Heating Units					**$30,572**	**$3,603**	**$34,174**		**11.78%**
Public School - Electric Heating (Tariff Code 642):									
Service Charge (Bills)	172	28.8500000		28.8500000	$4,962	$51,638	$56,601	$329.0700000	1040.63%
Energy Charge (KWH)	19,503,080	0.0464100	0.0158563	0.0305537	595,891		595,891	0.0305537	0.00%
Total Public School - Electric Heating					**$600,853**	**$51,638**	**$652,492**		**8.59%**
Total Base Public School Margin					**$950,074**	**$110,182**	**$1,060,256**		11.60%
TRA Inspection Fee Rider Surcharge					6,441	-6,441	0		-100.00%
Prompt Payment Discount					-32,301	-1,556	-33,857		4.82%
Net Base Public School Margin	**367**				**$924,214**	**$102,186**	**$1,026,399**		**11.06%**
	27,413,429								

SOURCE: CPAD Revenue Workpaper R-41-1.01 and CPAD Exhibit, Schedule 12.

Kingsport Power Company
CPAD Proposed Rate Design
Electric Heating General Service

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Electric Heating General Service:									
Electric Heating General - Regular (Tariff Code 208):									
Service Charge (Bills)	5,314	$25.1000000		$25.1000000	$133,381	$120,685	$254,066	$47.8100000	90.48%
Energy Charge (KWH)	20,527,982	0.0551600	$0.0158563	0.0393037	806,826		806,826	0.0393037	0.00%
Demand Charge (KW)	96,863	2.3100000		2.3100000	223,754		223,754	2.3100000	0.00%
Total Electric Heating General - Regular					**$1,163,961**	**$120,685**	**$1,284,645**		**10.37%**
Electric Heating General - Minimum (Tariff Code 209):									
Service Charge (Bills)	1,643	25.1000000		25.1000000	$41,239	$37,314	$78,553	$47.8100000	90.48%
Energy Charge (KWH)	4,214,295	0.0551600	0.0158563	0.0393037	165,637		165,637	0.0393037	0.00%
Demand Charge (KW)	25,847	0.0000000		0.0000000	0		0	0.0000000	0.00%
Total Electric Heating General - Minimum					**$206,877**	**$37,314**	**$244,190**		**18.04%**
Total Base Electric Heating General Service Margin					**$1,370,837**	**$157,998**	**$1,528,835**		11.53%
TRA Inspection Fee Rider Surcharge					7,509	-7,509	0		-100.00%
Prompt Payment Discount					-37,657	-2,257	-39,914		5.99%
Net Base Electric Heating General Service Margin	**6,957**				**$1,340,689**	**$148,232**	**$1,488,921**		**11.06%**
	24,742,277								
	122,710								

SOURCE: CPAD Revenue Workpaper R-42-1.01 and CPAD Exhibit, Schedule 12.

Kingsport Power Company
CPAD Proposed Rate Design
Outdoor Lighting Service

Tariff	Billing Determinants	Current Base Rates	Current Base Cost	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Outdoor Lighting Service:									
Lamps Charges:									
7000 Mercury Vapor (93)	3,096	$9.3500000	$0.0000000	$9.3500000	$28,948	$3,588	$32,536	$10.5100000	12.40%
9500 High Pressure Sodium (94)	33,558	7.1000000	0.0000000	7.1000000	238,262	29,533	267,795	7.9800000	12.40%
20000 Mercury Vapor (95)	389	16.1000000	0.0000000	16.1000000	6,263	776	7,039	18.1000000	12.40%
22000 High Pressure Sodium (97)	8,573	10.7000000	0.0000000	10.7000000	91,731	11,370	103,101	12.0300000	12.40%
27500 High Pressure Sodium Post Top (103)	48	36.9500000	0.0000000	36.9500000	1,774	220	1,993	41.5300000	12.40%
22000 High Pressure Sodium Floodlight(107)	5,020	11.3000000	0.0000000	11.3000000	56,726	7,031	63,757	12.7000000	12.40%
50000 High Pressure Sodium Floodlight (109)	1,355	15.7000000	0.0000000	15.7000000	21,274	2,637	23,910	17.6500000	12.40%
17000 Metal Halide Floodlight (110)	554	13.1000000	0.0000000	13.1000000	7,257	900	8,157	14.7200000	12.40%
9500 High Pressure Sodium Post Top (111)	3,603	11.6000000	0.0000000	11.6000000	41,795	5,181	46,975	13.0400000	12.40%
9500 High Pressure Sodium Floodlight (115)	1,285	9.0500000	0.0000000	9.0500000	11,629	1,441	13,071	10.1700000	12.40%
28800 Metal Halide Floodlight (116)	7,642	15.9000000	0.0000000	15.9000000	121,508	15,061	136,569	17.8700000	12.40%
50000 High Pressure Sodium Shoebox (120)	156	18.6500000	0.0000000	18.6500000	2,909	361	3,270	20.9600000	12.40%
16000 High Pressure Sodium Post Top (122)	276	34.4500000	0.0000000	34.4500000	9,508	1,179	10,687	38.7200000	12.40%
50000 High Pressure Post Top Floodlight (124)	48	40.0500000	0.0000000	40.0500000	1,922	238	2,161	45.0100000	12.40%
36000 Metal Halide Post Top Floodlight (126)	60	40.1000000	0.0000000	40.1000000	2,406	298	2,704	45.0700000	12.40%
Total Lamps	**65,663**				**$643,912**	**$79,815**	**$723,727**		**12.40%**
Facility Charges:									
Poles	6,306	7.9500000	0.0000000	7.9500000	$50,133		$50,133	7.9500000	0.00%
Spans	1,855	1.4000000	0.0000000	1.4000000	2,597		2,597	1.4000000	0.00%
Conduits	3,454	1.0000000	0.0000000	1.0000000	3,454		3,454	1.0000000	0.00%
Total Facility Charges					**$56,184**	**$0**	**$56,184**		**0.00%**
Total Base Outdoor Lighting Service Margin					**$700,095**	**$79,815**	**$779,910**		11.40%
TRA Inspection Fee Rider Surcharge					2,241	-2,241	0		-100.00%
Prompt Payment Discount					-11,240	-1,164	-12,404		10.35%
Net Base Outdoor Lighting Service Margin					**$691,096**	**$76,410**	**$767,507**		**11.06%**

SOURCE: CPAD Revenue Workpaper R-50-1.01 and CPAD Exhibit, Schedule 12.

Tariff Account, Vintage Rate, Structure, Lamp Size	Billing Determinants	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Street Lighting Service:							
Account 325:							
Unknown, Unknown, Unknown	12	$3.20	$38	$4	$43	$3.55	11.06%
Pre 1-1-95, Post Top, HPS-9500	4,536	5.22	23,678	2,618	26,296	5.80	11.06%
Pre 1-1-95, Existing Pole, HPS-9500	21,668	5.65	122,424	13,536	135,960	6.27	11.06%
Pre 1-1-95, Existing Pole, HPS-16000	2,880	6.60	19,008	2,102	21,110	7.33	11.06%
Post 1-1-95, Existing Pole, HPS-9500	38	7.34	279	31	310	8.15	11.06%
Pre 1-1-95, Existing Pole, MV-7000	1,347	7.62	10,264	1,135	11,399	8.46	11.06%
Pre 1-1-95, Existing Pole, HPS-22000	96	8.43	809	89	899	9.36	11.06%
Pre 1-1-95, Wood Pole, HPS-9500	13,390	10.71	143,407	15,856	159,263	11.89	11.06%
Pre 1-1-95, Post Top, HPS-16000	216	11.53	2,490	275	2,766	12.80	11.06%
Pre 1-1-95, Wood Pole, HPS-16000	1,296	11.66	15,111	1,671	16,782	12.95	11.06%
Pre 1-1-95, Wood Pole, MV-7000	298	12.69	3,782	418	4,200	14.09	11.06%
Pre 1-1-95, Aluminum, HPS-9500	48	12.71	610	67	678	14.12	11.06%
Pre 1-1-95, Existing Pole, MV-20000	115	12.85	1,478	163	1,641	14.27	11.06%
Pre 1-1-95, Wood Pole, HPS-22000	0	13.49	0	0	0	15.17	11.06%
Pre 1-1-95, Steel Pole, HPS-9500	132	15.79	2,084	230	2,315	17.54	11.06%
Pre 1-1-95, Steel Pole, HPS-16000	0	16.74	0	0	0	18.83	11.06%
Pre 1-1-95, Wood Pole, MV-20000	24	17.91	430	48	477	19.89	11.06%
Pre 1-1-95, Steel Pole, HPS-28000	12	19.47	234	26	259	21.62	11.06%
Pre 1-1-95, Steel Pole, MV-20000	140	22.99	3,219	356	3,574	25.53	11.06%
Pre 1-1-95, Fiberglass, HPS-16000	396	23.44	9,282	1,026	10,309	26.03	11.06%
Total Account 325	46,644		$358,628	$39,651	$398,279		
Account 425:							
Pre 1-1-95, Existing-EM, HPS-22000	408	$6.39	$2,607	$288	$2,895	$7.10	11.06%
Pre 1-1-95, Existing-Pole, HPS-22000	7,154	8.43	60,308	6,668	66,976	9.36	11.06%
Pre 1-1-95, Existing-Pole, HPS-28000	1,420	9.33	13,249	1,465	14,713	10.36	11.06%
Pre 1-1-95, Existing-Pole, HPS-50000	2,412	12.73	30,705	3,395	34,100	14.14	11.06%
Pre 1-1-95, Wood Pole, HPS-22000	780	13.49	10,522	1,163	11,686	14.98	11.06%
Pre 1-1-95, Wood Pole, HPS-28000	396	14.39	5,698	630	6,328	15.98	11.06%
Pre 1-1-95, Wood Pole, HPS-50000	504	17.80	8,971	992	9,963	19.77	11.06%
Pre 1-1-95, Steel Pole, HPS-22000	43	18.57	799	88	887	20.62	11.06%
Pre 1-1-95, Steel Pole, HPS-28000	2,716	19.47	52,881	5,847	58,727	21.62	11.06%
Pre 1-1-95, Steel Pole, HPS-50000	1,118	22.87	25,569	2,827	28,396	25.40	11.06%
Pre 1-1-95, Existing-EM, HPS-140000	1,152	24.46	28,178	3,115	31,293	27.16	11.06%
Pre 1-1-95, Fiberglass, HPS-28000	60	26.17	1,570	174	1,744	29.06	11.06%
Pre 1-1-95, Aluminum, HPS-28000	132	35.71	4,714	521	5,235	39.66	11.06%
Pre 1-1-95, Aluminum, HPS-50000	1,416	39.12	55,394	6,125	61,518	43.45	11.06%
Pre 1-1-95, Steel, HPS-140000	660	91.78	60,575	6,697	67,272	101.93	11.06%
Total Account 425	20,371		$361,739	$39,995	$401,734		

Kingsport Power Company
CPAD Proposed Rate Design
Street Lighting Service

Tariff Account, Vintage Rate, Structure, Lamp Size	Billing Determinants	Current Margin Rate	Current Margin	Margin Deficiency	Proposed Margin	Proposed Margin Rates	Percent Increase
Street Lighting Service:							
Account 625:							
Pre 1-1-95, Existing-Pole, HPS-9500	350	$5.65	$1,978	$219	$2,196	$6.27	11.06%
Post 1-1-95, Post Top, HPS-9500	548	6.79	3,721	411	4,132	7.54	11.06%
Post 1-1-95, Existing-Pole, HPS-9500	16,031	7.34	117,668	13,010	130,677	8.15	11.06%
Pre 1-1-95, Existing-Pole, MV-7000	0	7.62	0	0	0	8.57	11.06%
Post 1-1-95, Existing-Pole, HPS-16000	6,371	8.58	54,663	6,044	60,707	9.53	11.06%
Pre 1-1-95, Wood Pole, HPS-9500	70	10.71	750	83	833	11.89	11.06%
Post 1-1-95, Existing-Pole, HPS-22000	1,497	10.96	16,407	1,814	18,221	12.17	11.06%
Pre 1-1-95, Post Top, HPS-16000	108	11.53	1,245	138	1,383	12.80	11.06%
Post 1-1-95, Existing-Pole, HPS-28000	477	12.12	5,781	639	6,420	13.46	11.06%
Pre 1-1-95, Aluminum, HPS-9500	12	12.71	153	17	169	14.12	11.06%
Pre 1-1-95, Wood Pole, HPS-22000	0	13.49	0	0	0	15.17	11.06%
Post 1-1-95, Post Top, HPS-16000	9,605	13.58	130,436	14,422	144,857	15.08	11.06%
Post 1-1-95, Wood Pole, HPS-9500	9,434	13.93	131,416	14,530	145,945	15.47	11.06%
Post 1-1-95, Wood Pole, HPS-16000	1,086	15.17	16,475	1,821	18,296	16.85	11.06%
Post 1-1-95, Fiberglass, HPS-9500	180	16.54	2,977	329	3,306	18.37	11.06%
Post 1-1-95, Existing-Pole, HPS-50000	719	16.55	11,899	1,316	13,215	18.38	11.06%
Post 1-1-95, Wood Pole, HPS-22000	367	17.55	6,441	712	7,153	19.49	11.06%
Post 1-1-95, Wood Pole, HPS-28000	144	18.71	2,694	298	2,992	20.78	11.06%
Post 1-1-95, Wood Pole, HPS-50000	60	23.14	1,388	154	1,542	25.70	11.06%
Pre 1-1-95, Fiberglass, HPS-16000	72	23.44	1,688	187	1,874	26.03	11.06%
Post 1-1-95, Steel Post, HPS-28000	192	25.31	4,860	537	5,397	28.11	11.06%
Post 1-1-95, Aluminum, HPS-28000	845	25.81	21,809	2,411	24,221	28.66	11.06%
Post 1-1-95, Steel Post, HPS-50000	509	29.74	15,138	1,674	16,811	33.03	11.06%
Post 1-1-95, Fiberglass, HPS-28000	660	35.22	23,245	2,570	25,815	39.11	11.06%
Pre 1-1-95, Aluminum, HPS-28000	120	35.71	4,285	474	4,759	39.66	11.06%
Post 1-1-95, Fiberglass, HPS-50000	204	39.65	8,089	894	8,983	44.03	11.06%
Post 1-1-95, Aluminum, HPS-22000	156	45.26	7,061	781	7,841	50.26	11.06%
Post 1-1-95, Aluminum, HPS-28000	938	46.42	43,542	4,814	48,356	51.55	11.06%
Post 1-1-95, Aluminum, HPS-50000	2,218	50.85	112,785	12,470	125,255	56.47	11.06%
Total Account 625	**52,973**		**$748,592**	**$82,767**	**$831,360**		
Account 725:							
Unknown, Unknown, Unknown	79	$3.20	$253	$28	$281	$3.55	11.06%
Pre 1-1-95, Existing-Pole, HPS-9500	5,907	5.65	33,375	3,690	37,065	6.27	11.06%
Pre 1-1-95, Existing-Pole, HPS-16000	372	6.60	2,455	271	2,727	7.33	11.06%
Unknown, Unknown, Unknown	12	6.75	81	9	90	7.50	11.06%
Post 1-1-95, Post Top, HPS-9500	552	6.79	3,748	414	4,162	7.54	11.06%
Post 1-1-95, Existing-Pole, HPS-9500	14	7.34	103	11	114	8.15	11.06%
Post 1-1-95, Aluminum, HPS-9500	38	16.54	629	69	698	18.37	11.06%
Total Account 725	**6,974**		**$40,643**	**$4,494**	**$45,137**		
Total Base Street Lighting Service Margin			**$1,509,602**	**$166,908**	**$1,676,509**		11.06%
TRA Inspection Fee Rider Surcharge			0	0	0		0.00%
Prompt Payment Discount			0	0	0		0.00%
Net Base Street Lighting Service Margin	**126,962**		**$1,509,602**	**$166,908**	**$1,676,509**		**11.06%**

SOURCE: CPAD Revenue Workpaper R-51-2.00 to 2.03 and CPAD Exhibit, Schedule 12.